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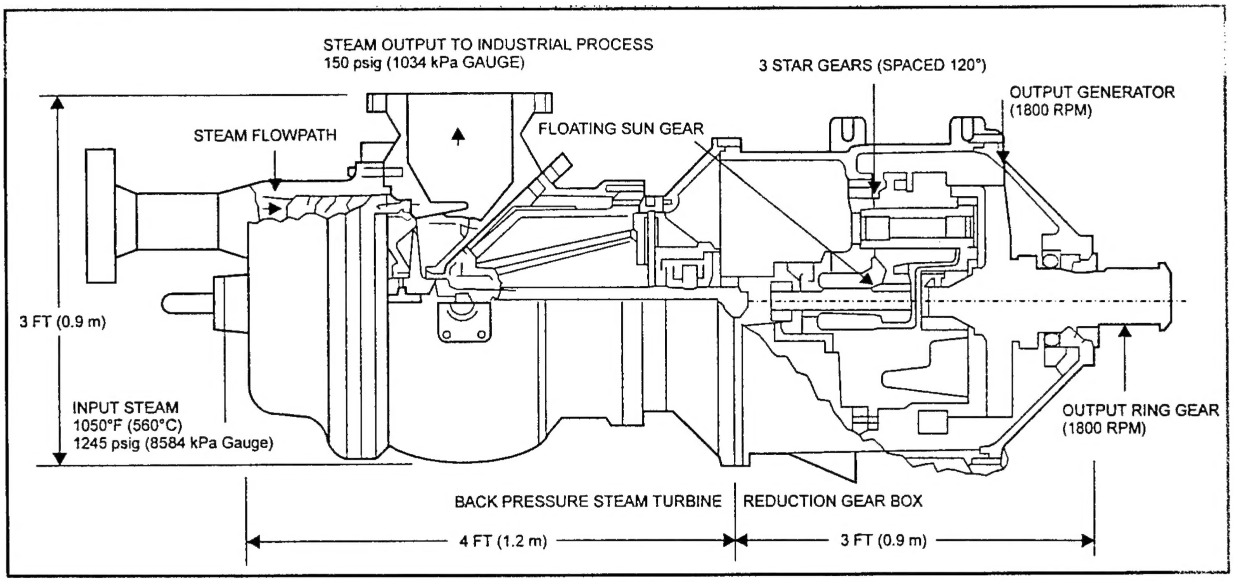
Assessment of Cogeneration Technologies for Use at Department of Defense Installations

by
Michael J. Binder and Gerald L. Cler



Cogeneration is the simultaneous generation of two types of energy, usually electricity and thermal energy, from a single energy source such as natural gas or diesel fuel. Cogeneration systems can be twice (or more) as efficient than conventional energy systems since both the electricity and the available thermal energy produced as a by-product of the electric generation, are used.

This study identified cogeneration technologies and equipment capable of meeting Department of Defense (DOD) requirements for generation of electrical and thermal energy and described a wide range of successful cogeneration system configurations potentially applicable to DOD energy plants, including: cogeneration system prime movers, electrical generating equipment, heat recovery equipment, and control systems. State of the art cogeneration components are discussed in detail along with typical applications and analysis tools that are currently available to assist in the evaluation of potential cogeneration projects. A basic analysis was performed for 55 DOD installations to determine the economic benefits of cogeneration to the DOD. The study concludes that, in general, cogeneration systems can be a very cost effective method of providing the military with their energy needs.

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Foreword

This study was conducted for U.S. Army Center for Public Works (USACPW) under Project 4A162784AT45, “Energy and Energy Conservation”; Work Unit EQ-XV3, “Advanced Electrical Generation and Supply Technologies.” The technical monitor was Thomas Luu, CECPW-FU-E.

The work was performed by the Utilities Division (UL-U) of the Utilities and Industrial Operations Laboratory (UL), U.S. Army Construction Engineering Research Laboratories (USACERL). The USACERL principal investigator was Michael Binder. Martin J. Savoie is Chief, CECER-UL-U; John T. Bandy is Operations Chief, CECER-UL; and Gary W. Schanche is Chief, CECER-UL. The USACERL technical editor was William J. Wolfe, Technical Resources.

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1 Introduction

Background

The term "cogeneration" refers to the simultaneous generation of two types of energy, usually electrical and thermal, from an energy source such as natural gas or diesel fuel. Cogeneration plants offer several advantages over conventional facilities. A cogeneration system's ability to capture energy output in two forms makes it more efficient than conventional energy systems, and results in lower overall operating costs. Many cogeneration plants are designed to use more than one fuel. Such fuel flexibility makes the plant a more reliable source of electricity, reduces its impact on the environment, lessens its vulnerability to fluctuations in fuel prices and availability, and generally lengthens the plant's useful life.

For example, a typical commercial or industrial facility produces steam or hot water in a boiler and purchases electricity from the local utility. The typical power generating plant may be only 35 percent efficient—or less. A cogeneration unit, by contrast, can be over 80 percent efficient. These higher efficiencies can reduce operating costs to make packaged cogeneration systems economically attractive to Department of Defense (DOD) facilities where there is often a simultaneous demand for thermal and electrical energy in the form of domestic hot water (DHW), process steam, heating, or cooling (via absorption chillers).

Objective

This study is meant to give sufficient background information on cogeneration and to describe recently developed cogeneration technologies for DOD plant managers to consider cogeneration applications as potential alternatives to conventional energy plant technologies when considering energy plant upgrades or replacement at DOD installations.

Approach

The first phase of this study identified cogeneration technologies and equipment capable of meeting DOD requirements for generation of electrical and thermal energy. The second phase identified and described a wide range of successful cogeneration system configurations potentially applicable to DOD energy plants.

Scope

This document provides general information on the status of cogeneration technology, including applications, hardware configurations, economic assessment information, and potential vendors for both large and small cogeneration systems. Regulations, ownership issues, and environmental concerns are also addressed.

Mode of Technology Transfer

It is recommended that the information in this report be summarized in a Engineer Technical Note (ETN) describing cogeneration technologies as a method of reducing operating costs and energy consumption at DOD installations.

Metric Conversion Factors

The following metric conversion factors are provided for standard units of measure used throughout this report:

1 in.	=	25.4 mm
1 ft	=	0.305 m
1 lb	=	0.453 kg
1 gal	=	3.78 L
1 psi	=	6.89 kPa
1 ton (refrigeration)	=	3.516 kW
°F	=	(°C x 1.8) +32
1 BTU	=	1.055 kJ

2 Benefits and Potential Applications of Cogeneration

Advantages of Cogeneration

A cogeneration system generates electric power and thermal energy sequentially from the same fuel source. Cogeneration systems have a higher overall efficiency than conventional energy systems because cogeneration allows both the electric and thermal outputs to be used. In conventional energy systems, steam or hot water is produced in a boiler, and electricity is purchased separately from a local utility. While the efficiencies of a typical electric power generation plant may be as low as 35 percent (or less), the combined electrical and thermal efficiency of a cogeneration system can be over 80 percent. Utility cost reductions associated with high efficiencies can make cogeneration systems economically attractive for DOD facilities, where there is often a simultaneous demand for domestic hot water (DHW), process steam, heating or cooling (such as absorption), and electrical energy. The U.S. Department of Energy (DOE) has estimated that switching from a conventional to a cogeneration system can reduce fuel requirements by 10 to 30 percent, and yield an associated return-on-investment (ROI) of 20 percent or more per year (Freeman and Blazek 1992). For most cogeneration systems, the simple pay-back period is from 2 to 4 years.

Cogeneration also offers the advantage of fuel flexibility. Many cogeneration systems can burn such fuels as natural gas, propane, coal-derived liquids and gases, and diesel fuel. Because of their higher operating efficiencies and reduced fuel consumption, cogeneration systems produce less thermal pollutants than conventional systems while providing the same quantity of useful energy. The use of cogeneration can ease electrical purchase requirements in areas faced with shortages of electrical power. Cogeneration systems also provide improved power reliability. Their decentralized locations for power generation make them less vulnerable to various disasters or blackouts.

The thermal output from the cogeneration unit can be used to provide domestic hot water or space heating, to drive an absorption air-conditioning unit, or to heat a swimming pool. The cogeneration unit can be thermally dispatched (in the thermal following mode) to shut down automatically when there is no demand for hot water. The cogeneration unit can also be run at full capacity, in which case any excess thermal output is dumped to ambient air in a radiator. The third mode in which a

cogeneration unit can run is the "electric following mode," in which the cogeneration unit follows the electrical load. (However, packaged cogeneration systems [PCSs] are not usually operated in this mode.)

Packaged Cogeneration Systems

The term "Packaged Cogeneration System" refers to cogeneration systems that are pre-engineered and factory assembled and tested. PCSs are skid-mounted units, generally below about 500 kW in capacity. Packaged cogeneration systems are applicable to individual DOD facilities or small complexes that have a thermal demand for DHW, process steam, heating, and cooling. The electricity generated is distributed to the grid.

PCSs have shown to be reliable in part because they are factory-assembled from components manufactured in large quantities. Because the system is completely packaged at the factory, installation cost is low compared to site-specific cogeneration systems. PCSs are also more compact and require less space than field-erected systems and are therefore emerging as the preferred system type.

A PCS usually consists of a prime mover, such as a reciprocating engine or gas turbine, and heat recovery equipment that generates steam or hot water for domestic hot water, space heating, absorption cooling, or industrial process heat. Thermal energy storage, such as a hot water storage tank, may also be added to the system to better use the waste heat and improve the cost savings. A variety of hardware configurations are commercially available (Table 1).

PCS Applications and Market Potential

Many applications in commercial and DOD sectors have sufficient electric and thermal loads to make packaged cogeneration attractive. Since 1982, the Gas Research Institute (GRI) has been developing and commercializing PCS technology for these

Table 1. Small cogeneration system options.

Prime Movers	Fuels	Generator	Heat Recovery
Reciprocating engines Gas turbines Steam turbines	Natural gas Diesel fuel Gasoline Propane Sewage digester gas Landfill gas	Induction Synchronous	Heat exchangers Dryers Waste heat boilers Absorption chillers

applications (King and Lorand 1991). Several packaged systems ranging from a few tens to several hundred kilowatts have been developed and tested for various applications. For applications where the hot-water demand is not large, the PCS can be integrated with an HVAC system to supply electricity, heating, cooling, and domestic hot water simultaneously. The cooling provided by the PCS is generated by a hot water or low-pressure steam-driven absorption chiller. As an HVAC option, cogeneration is particularly attractive in the new and retrofit markets where the cost of displaced HVAC equipment may be taken as a credit.

Some of the applications in the commercial sector include apartment buildings, supermarkets, restaurants, hotels/motels, and hospitals, all of which are applications with sufficient thermal load (primarily hot water) and electric demand to make PCS economically feasible. Table 2 lists building types where PCS may prove economical and the associated approximate kW range. (This estimate was developed by the Gas Research Institute from detailed research of the markets.) Taken into account were various factors affecting the feasibility of cogeneration at a particular site, such as hours of operation per year, the heating, cooling, and electrical system efficiencies at various loads, and grid interconnection requirements.

Several PCSs were specifically developed for particular commercial applications. GRI has developed and tested three packages for hospitals, supermarkets, and restaurant applications. The hospital package is a 500-kW cogeneration package with a 150-ton absorption chiller. The restaurant package is a 70-kW unit with a 35-ton chiller. The supermarket unit is a 97-HP gas engine that drives a 10-ton mechanical chiller.

Several types of DOD facilities may benefit from PCSs. These include bachelor officer/enlisted quarters, dining facilities, hospitals, laundry facilities, heated swimming pools, and industrial facilities. Any facility that meets the following conditions is considered as a possible candidate for small cogeneration:

1. Electric-to-fuel cost differential of \$15/MBTU or higher.
2. A thermal load of at least 100,000 Btu/hr. (This is equivalent to the electrical output of a 20 kW cogeneration unit for a minimum of 4,000 hours of operation per year.)

Table 2. Selected commercial, institutional, and multi-unit technically feasible sites.

Principal Building Activity*	Electricity Consumption per Building (kWh x 1000)	Peak Electrical Demand per Building (kW)
Education	229	101-250
Food sales	253	101-250
Health care	638	251-1,000
Lodging	360	101-250
Office	275	101-250

* Source: U.S. Department of Energy (April 1995).

Large Cogeneration Systems

Large cogeneration systems (LCS) with electrical generation capacities above 500 kW are applicable to installation-wide power generation. The technology for LCS is both proven and commercially available. The LCS normally involves a site-specific design that includes commercially available prime movers such as gas turbines, diesel engines, and steam turbines. Electricity (or mechanical power) and thermal energy can be generated by either a topping or bottoming cycle system. In a topping cycle system, fuel is burned to generate electricity and the waste heat is used for an industrial application or for space heating. In a bottoming cycle, the reverse is true. Fuel is burned to produce high-pressure steam and the resulting low-pressure steam is then used to drive a turbine, producing electricity. Table 3 lists the characteristics of several cogeneration options. The advantages and disadvantages of each option must be considered when selecting a prime mover for a specific project.

Analysis Tools

From the time a cogeneration application is first conceived until it reaches the final design stage, it typically goes through a series of increasingly refined and detailed analysis. The analysis process can be broken down to a three-level process, each level more detailed and consequently more costly in terms of time and money. Table 4 outlines this three-level approach and gives estimates of time and costs to perform the study.

Table 3. Characteristics of cogeneration options.

Technology	Advantages	Disadvantages
Steam turbines and boiler	• Long life (~ 40 years) • Can burn coal and other nonpremium fuels • Established, well understood technology	• Low electric efficiency (<30%) • Not easily operated at part load. • Uneconomic at small sizes • Plant cannot be operated unattended. • Thermal/electric efficiency is low (50–60%). • Air pollution problems
Gas turbines	• High temperature heat • High ratio of recoverable heat • Compact, lightweight • Easily set up • Low maintenance requirements • Short lead time • Good flexibility	• Natural gas or petroleum-based fuels required • Thermal/electric efficiency is low (70%) • Noisy (siting restraints)
Diesel and gas engines	• Reliability • High electrical efficiency • Small/intermediate size • Low initial cost	• Siting of storage tanks • Low grade waste heat • Natural gas or petroleum-based fuels required • Air pollution problems

Table 4. Typical cogeneration feasibility analysis.

Type	Depth	Basis	Engineering Scope	Cost Accuracy	Study Time (Work-Hours)	Study Costs (k$)
Level I	Screening study	Annual ave. loads	• Annual T/E ratio • Cycle selection • Conceptual design • Budget estimates • Go, no-go decision • Memo report	± 30 %	4 – 10 1 site visit	1 – 2
Level II	Preliminary study	Monthly ave. loads	• On-line diagrams • Monthly load profiles • Load duration curves • System configuration • Approx. unit sizing • Control oper. strategy • General layout	± 20 %	40 – 100 2 site visits	4 – 10
Level III	Detailed study	Hourly ave. loads	• Hourly, comprehensive evaluation of site data • Many cycle options • Load-leveling options • Optimum unit sizing • Equipment lists • Vendor quotes	± 10 %	200 – 800 Multiple site visits	20 – 50

A variety of computer software products are available to help the planner evaluate the performance and economic potential of cogeneration systems. Appendix A describes a number of programs, including software capabilities, points of contact, and other information. Note that *these computer programs cannot replace engineering analysis*, but can help the engineer doing the analysis by reducing the number of repetitive calculations often required to perform a thorough optimizing analysis. These programs range in sophistication from providing simple screening study level analyses through very detailed analyses using hourly data.

3 Cogeneration System Components

Simple Cycle

In a simple gas turbine power cycle (Figure 1), compressed air enters the combustor where fuel combustion drives the turbine, which in turn drives a generator to create electricity. The hot exhaust gases are then released to the atmosphere. By adding a heat recovery steam generator, the cycle becomes a simple cogeneration cycle that uses the heat of the exhaust gas to produce steam for heating or process needs (Figure 2).

Combined Cycle

A combined cycle (Figure 3) consists of a simple cogeneration cycle with the addition of a steam turbine to convert the steam from the heat recovery steam generator into additional electricity. This increases the power output of the system and the system efficiency. This configuration can also be used to provide process steam by bleeding some steam from the steam turbine for heating (Figure 4). Information in Table 5 shows that combined cycle plants have the highest electrical conversion efficiency of commonly used power generation systems.

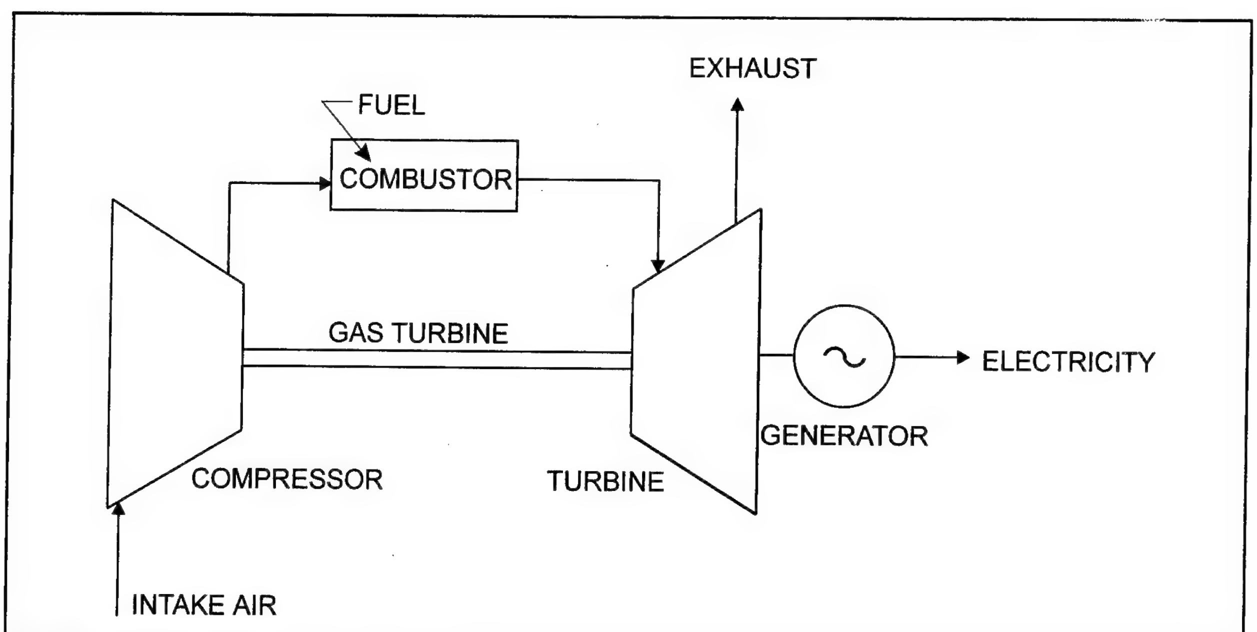


Figure 1. Simple gas turbine power cycle.

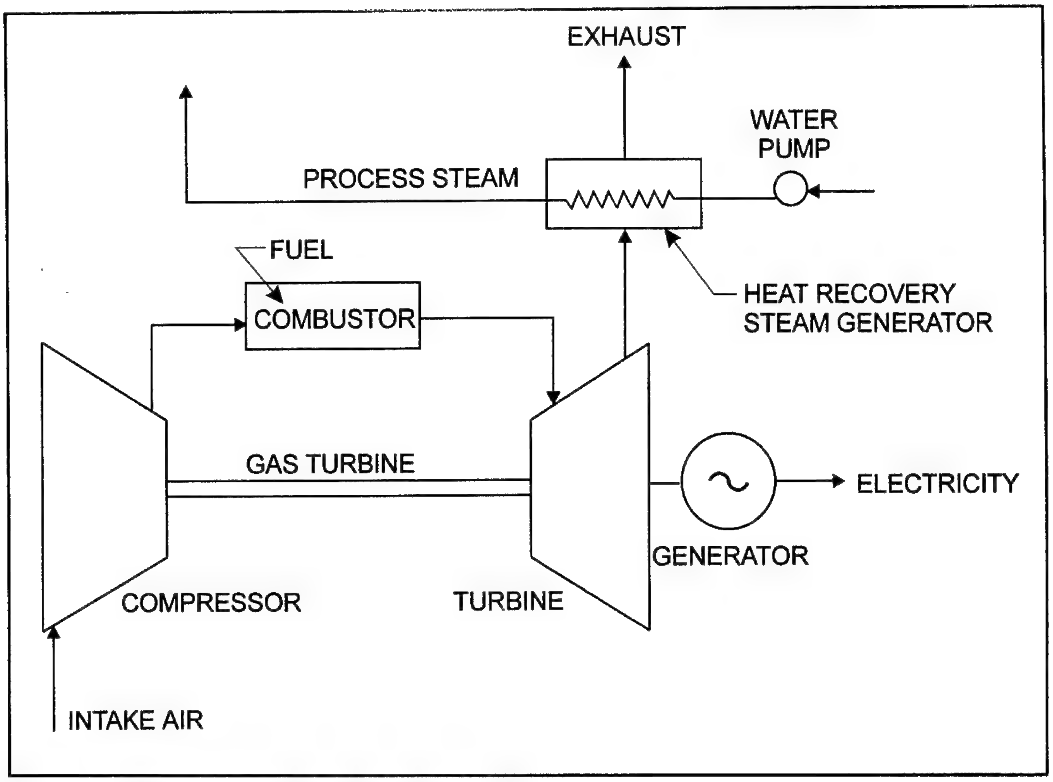


Figure 2. Simple gas turbine cogeneration cycle.

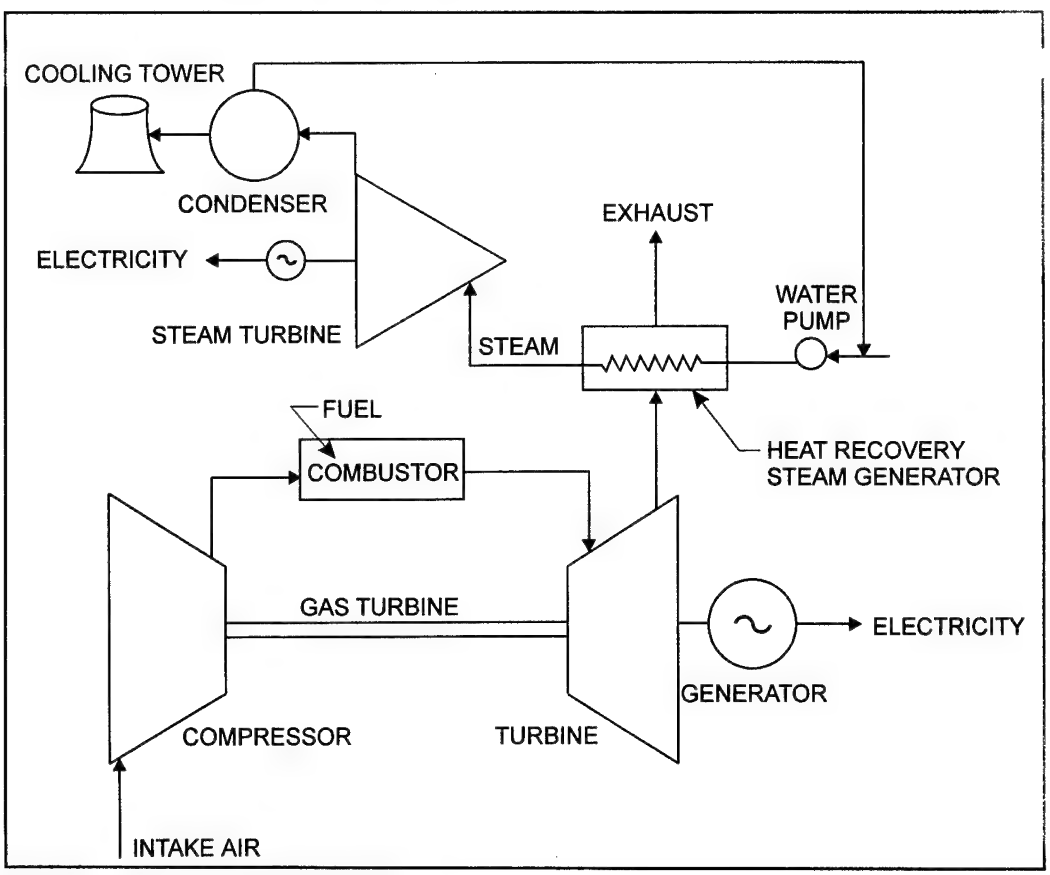


Figure 3. Combined cycle for power.

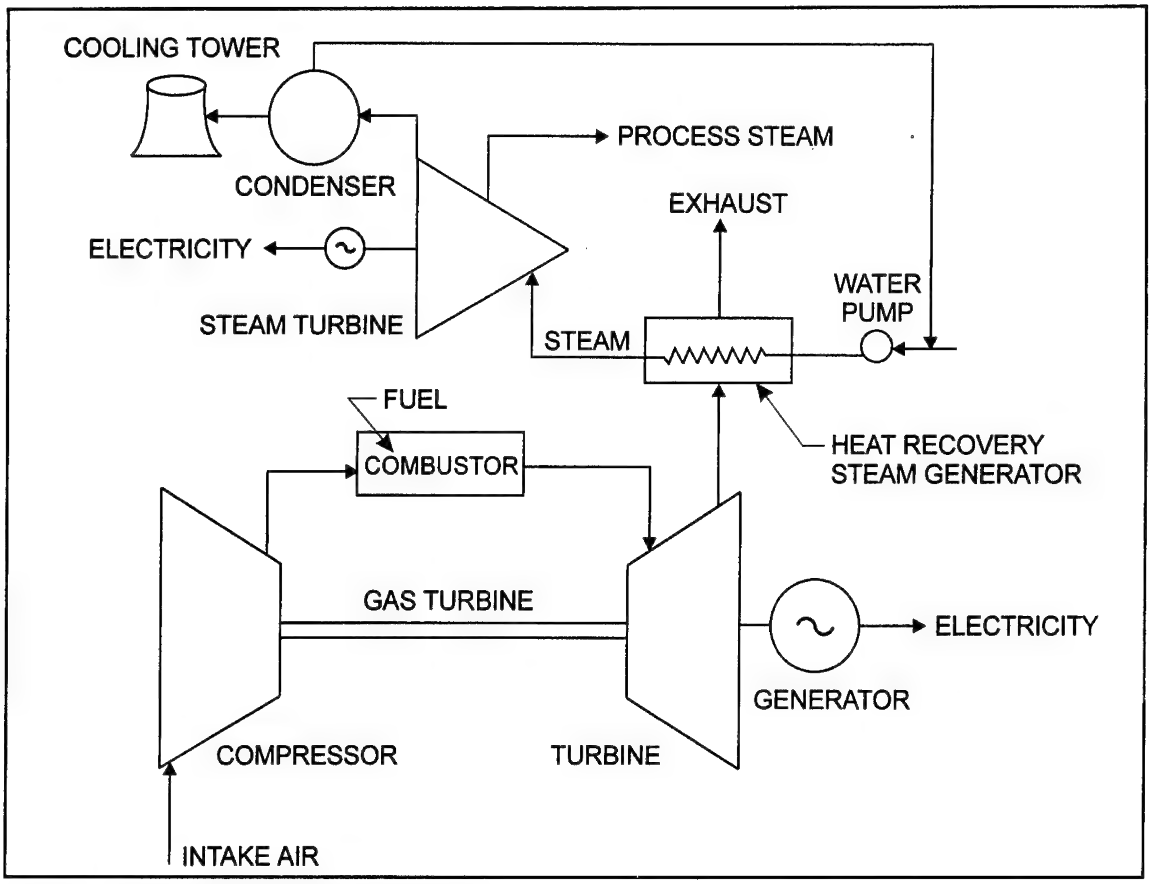


Figure 4. Combined cycle for cogeneration.

Table 5. Cogeneration tradeoffs.

Technology	Capitol Cost ($/kW)	Fuel Type	Fuel Cost ($/mBTU)	Efficiency	SOx lb/mBTU	NOx Removal	lb/mBTU
Simple-cycle gas turbine	350	Gas	3.0	35%	0		0.10
Combined cycle	650	Gas	3.0	53%	0		0.03
Pulverized cola	1400	Coal	1.7	36%	4	95	0.30
IGCC	1500	Coal	1.7	42%	4	98	0.03
Fluidized bed	1400	Coal	1.7	37%	4	95	0.10

Reheat Combustors

Reheat combustors are used to increase the power output of steam turbines. In this system, the steam turbine is physically separated from the gas turbine. The steam exhaust from the gas turbine flows through a reheat combustor that increases the temperature of the exhaust. Since the power output of the steam turbine is proportional to the turbine inlet temperature, a reheat combustor increases the capacity of

the system and raises the temperature of the power turbine exhaust. The high temperature exhaust can then be used for process steam applications and for heating.

Steam-Injected Gas Turbine or Cheng Cycle

The steam-injected gas turbine (STIG) or Cheng cycle (Figure 5) is similar to the simple cogeneration cycle except that excess process steam is injected into the combustor. Steam injection can reduce fuel consumption at a given output or can maximize power output of the system. In addition, steam not needed for heating or process use could be converted into additional power. Steam injection also lowers NO_x emissions, provides better part-load performance, and increases the flexibility of a cogeneration system. Although the STIG cycle is not as efficient as a combined cycle, it has several advantages including lower capital costs, higher availability, possibility of remote operation, and lower water requirements. Because of these features, the STIG cycle is well-suited for smaller scale and variable steam load applications. Currently, about 36 STIG plants operate in the United States, Japan, and Italy, ranging in size from 2.3 to 51 MW. These plants are primarily produced by Kawasaki, Allison, and General Electric.*

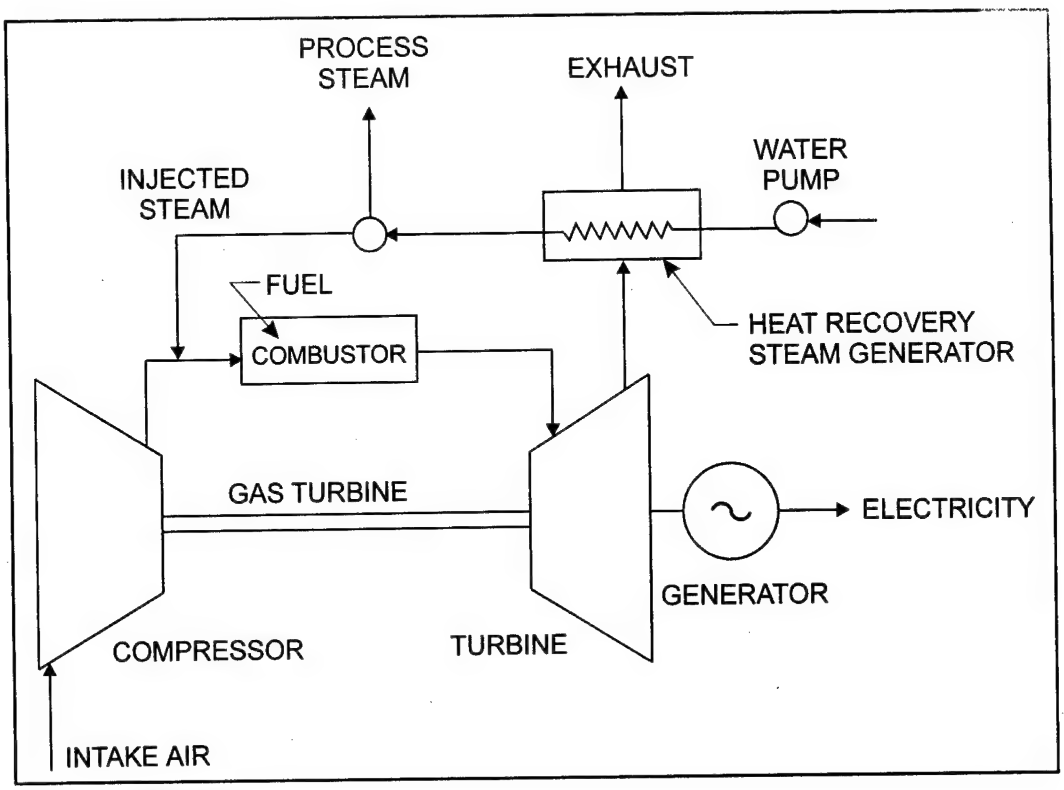


Figure 5. STIG cycle.

* Appendix B lists contact information for manufacturers cited in this report.

Intercooled Steam-Injected Gas Turbine Cycle (I-STIG)

Another gas turbine cycle is the intercooled STIG or I-STIG (Figure 6), which uses intercooling between the two compressor stages as well as steam injection. Intercooling improves the efficiency of the compressor, thus reducing the amount of energy drawn from the system. In addition, many aero-derivative turbines use high pressure air bled from the compressor to cool the turbine blades. Intercooled compressors produce lower air temperatures to keep the metal turbine blades sufficiently cool, allowing the turbine inlet temperature to be raised to increase efficiency.

Based on turbine performance, General Electric has projected that an I-STIG system can produce 110 MW at 47 percent efficiency. Adding I-STIG to larger turbines is expected to increase efficiency to 52 percent. The projected efficiency for the I-STIG is higher than that for advanced combined cycles and the projected cost is also slightly lower. Although the capacity of these prototype systems is on a utility scale, the I-STIG concept has potential to be scaled down for DOD installation applications.

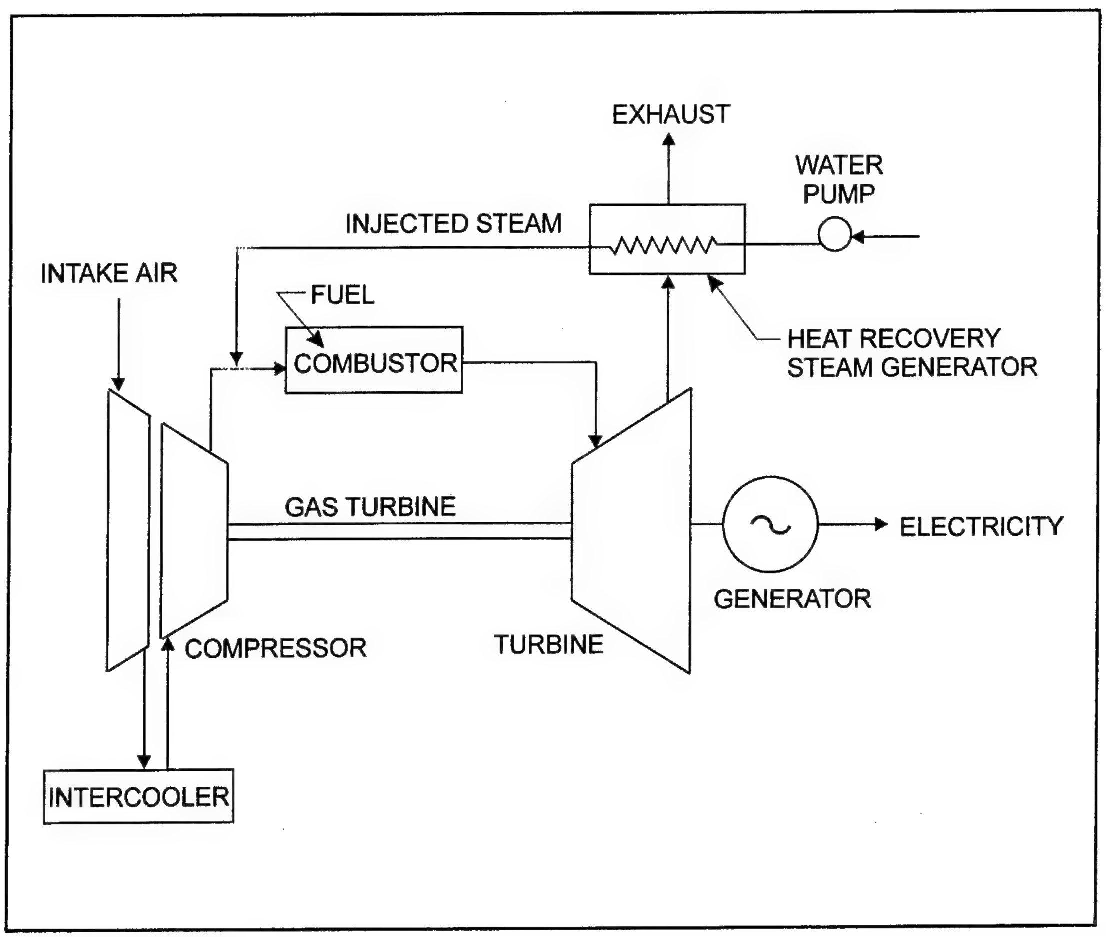


Figure 6. I-STIG cycle.

Air Bottoming Cycle

The air-bottoming cycle (ABC), developed by General Electric, is designed to recover waste heat from gas turbine exhaust (Figure 7). Instead of the waste heat boiler and steam turbine found in most combined cycles, the ABC uses an “air turbine” to convert the exhaust into mechanical power, eliminating the equipment needed for a steam-bottoming cycle including the boiler, pumps, condenser, and water treatment systems. The ABC is less efficient than a combined cycle system, but its lack of complex components results in lower capital costs and reduced operation and maintenance (O&M) costs. The ABC turbine promises to increase gas turbine shaft work by 30 to 35 percent and improve efficiency relative to a simple cycle by 25 percent.

Recuperated/Intercooled Cycle

In a recuperated cycle, exhaust heat is used to preheat the air entering the gas turbine combustor, resulting in a 5 to 10 percent increase in efficiency. Because of the improved performance and the simplicity of the recuperated cycle, this concept is very cost-effective. Intercooling is used to improve the efficiency of the compressors, which in turn improves the overall system efficiency. Combining the two cycles allows intercooling to enhance the benefits of the recuperated cycle by lowering the exit temperature of the compressor, enabling most of the exhaust heat to be used in the preheating process. The recuperated/intercooled cycle also improves part-load performance.

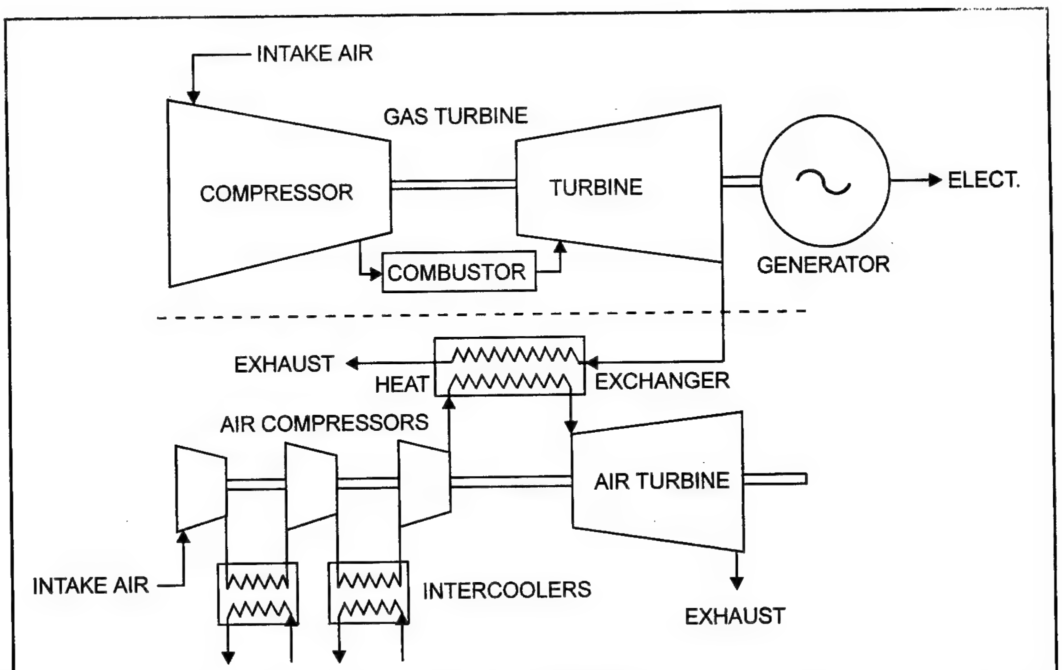


Figure 7. The air-bottoming cycle.

Intercooling was added to the already developed, recuperated Caterpillar-Solar gas turbine prototype. An increase in efficiency from 34 to 38 percent (low heat value [LHV]) was predicted with a corresponding increase in capacity from 2.7 to 3.5 MW. A design study estimated an increase in capacity from 4.6 to 6.4 MW with an efficiency of 41 percent (LHV) by retrofitting a Dresser Rand 990 gas turbine with recuperation and intercooling. Part-load efficiencies were projected to remain from 35 to 50 percent of rated power. Both studies found recuperation/intercooling to be cost-effective.

Chemically Recuperated Gas Turbine

A heat recovery steam reformer (HRSR) uses chemical means to recover thermal energy from the gas turbine exhaust. The highly endothermic chemical reaction between steam and desulfurized natural gas is driven by the high temperature of the exhaust heat. Methane is converted or reformed into hydrogen and carbon monoxide, which enhances the heating value of the fuel, improves the thermal efficiency of the system, and produces a sulfur-free, ultra-clean burning fuel gas. The chemically recuperated gas turbine has the potential to achieve higher efficiencies with lower emissions than current heat recovery steam generator systems.

The California Energy Commission and Pacific Gas and Electric are sponsoring General Electric Co. to analyze the cycle performance and heat balance of a GE I-STIG turbine with reheat and chemical recuperation. When combined with advanced gas turbine designs, HRSR technology can provide improved heat rates for power generation, emission control, and increased power output. The system has a projected efficiency of 60 percent (LHV).

Development of thermo-chemical recuperation (TCR), based on the same concept as the HRSR, is being conducted at the Institute of Gas Technology (IGT). IGT has developed burner systems that maintain a stable flame with hydrogen and carbon monoxide fuel mixtures. In addition to gas turbines, TCR concepts could be applied to high temperature furnaces and lean-burn internal combustion engines. Future studies at IGT will examine heat exchanger configurations and catalyst combinations for an advanced TCR heat recovery system.

Anderson Quinn Cycle

The Anderson Quinn cycle consists of five distinct subcycles that combine to increase thermal efficiency and produce higher power output than conventional gas turbine cycles. The cycle design incorporates advanced cooling systems and improved heat

transfer surfaces. All equipment used in the Quinn cycle has already been operated in various industrial installations. The proven reliability of this equipment promises to reduce maintenance requirements.

Thermal efficiencies of 62 percent are predicted based on a 2000 °F combustion temperature and a 80 °F ambient temperature. Power output is expected to increase up to six times that of a single gas turbine. The National Institute of Standards and Technology, Office of Energy Related Inventions has approved this new cycle and the DOE supports further analysis and economic evaluation.

The Anderson Quinn cycle is based on the patented Anderson power cycle (Figure 8). The Anderson power cycle is a binary, two-fluid (water and R-22 refrigerant) cycle with a projected efficiency up to 37 percent higher than the basic steam turbine cycle. This increase in efficiency is due to lower condensing temperatures (60 °F), lower expansion ratios, use of two sets of turbines, and an operating pressure above atmospheric pressure. The cycle also uses R-22 turbines, which have a higher efficiency

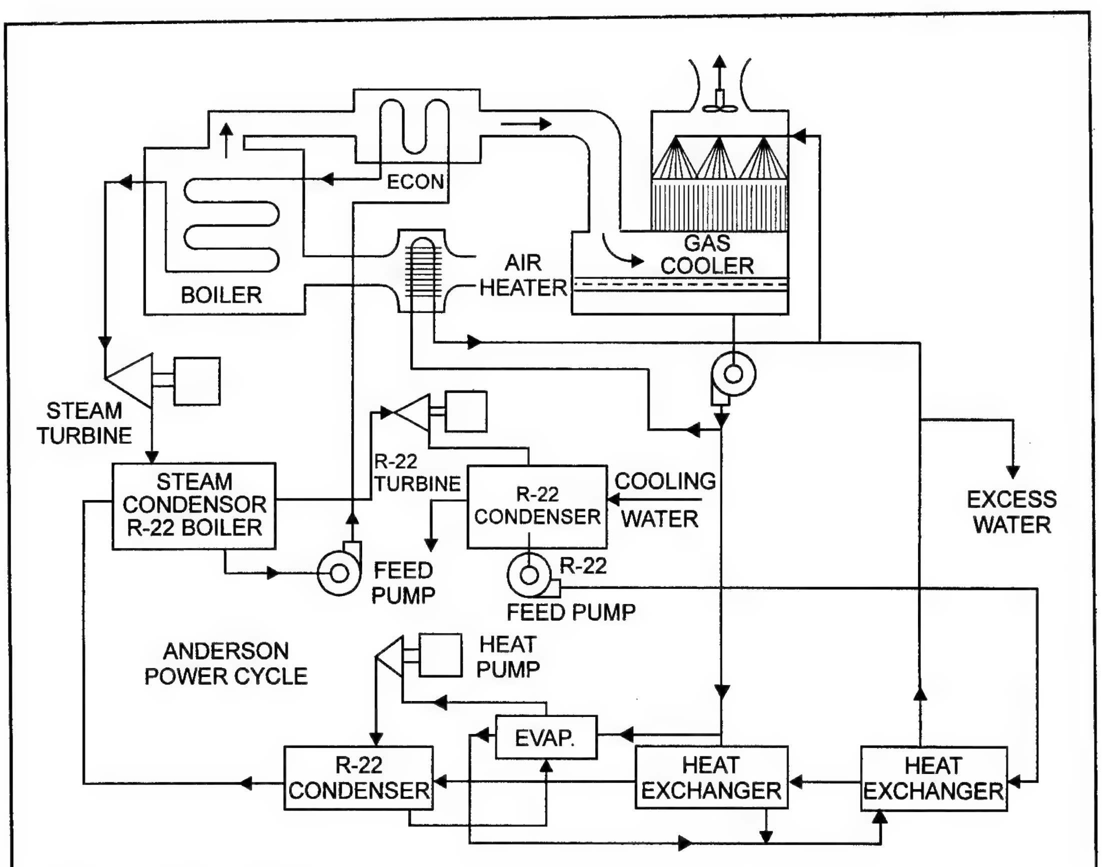


Figure 8. Anderson power cycle.

(90 percent) than steam turbines. The Anderson cycle is also predicted to have low maintenance and low emission levels.

Closed-Cycle Gas Turbine

In the closed-cycle concept (Figure 9) externally generated heat is transferred to a working fluid that circulates in a closed loop. Helium is commonly used as the working fluid due to its high thermal conductivity and its inert properties. Use of an inert working fluid reduces the possibility of corrosion, and allows turbine inlet temperature to be increased to improve the cycle efficiency without the need for protective coating or blade cooling. By separating combustion from the working fluid, the system can maintain its efficiency even at part load. Separate combustion also facilitates emissions control. The addition of a radiant-convective natural gas heater could virtually eliminate NO_x, CO, and unburnt hydrocarbons.

A prototype closed cycle gas turbine (CCGT) engine was developed with the support of the U.S. Navy. Using helium diluted with Xenon as the working fluid, the prototype had a capacity of 30 kW with an efficiency of 41.8 percent (LHV). With the addition of super-alloy rotating machinery and a ceramic combustor-heater, the CCGT could operate with a turbine inlet temperature up to 1800 °F at an efficiency high enough to match or exceed that of other power-generating cycles.

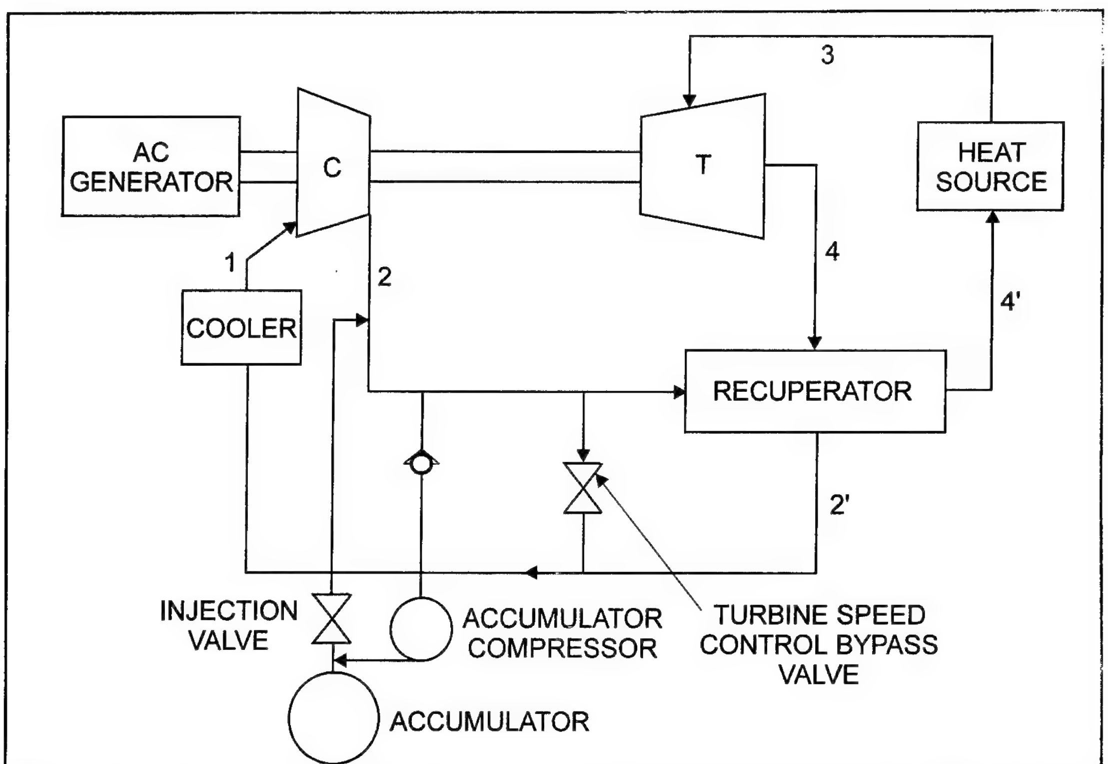


Figure 9. Closed cycle gas turbine.

Although some closed cycle gas turbine power plants were built in Europe over 35 years ago and smaller CCGTs were developed in the United States for special applications, the CCGT has not had the widespread success of other power plant cycles. However, recent technological developments and changing economic factors may allow the CCGT to potentially compete with other externally fired power plants and internal combustion engines, especially in the capacity range of 200 to 5000 kW.

Gas Turbine-Driven Packaged Cogeneration

Packaged cogeneration systems provide a means to reduce both engineering and manufacturing costs by standardizing designs and minimizing the amount of expensive site construction. This is especially beneficial in small cogeneration systems (less than 2 MW) where engineering and installation costs represent a significant portion of the system's initial cost. Several cogeneration systems in this size range are also based on reciprocating engines and produce hot water or low pressure steam. These systems will be discussed in the following sections. Teledyne Continental Motors TIR-500 Gas Turbine Engine.

The TIR-500 gas turbine system designed by Teledyne consists of a modified simple cycle general aviation turboprop engine. The original TP500 engine was converted to natural gas. Engine speed was lowered for improved durability and a recuperator was added to improve fuel economy. The system also includes a heat recovery steam generator (HRSG) and a microprocessor based digital control system. The system footprint is 5 ft wide by 5 ft high, which increases to 6.5 ft high with the HRSG.

The TIR-500 produces thermal output in the form of 100 psig steam. Based on design goals, a capacity of 225 kW is projected with an overall efficiency of 67 to 79 percent (based on LHV) and a steam rating of 1000 to 1900 lb/h.

Solar Turbine's Gas-Fired Combined Cycle System

Although very efficient for large scale plants, combined-cycle systems have not previously been cost-effective for plants under 20 MW. This is due to the high capital cost of the system and relative inefficiency of small steam turbines. To solve this problem, Solar Turbines Inc. has developed a 4.8 MW back-pressure steam turbine which, combined with an 8.6 MW gas turbine, can produce an overall thermal efficiency of 75 percent (Figure 10).

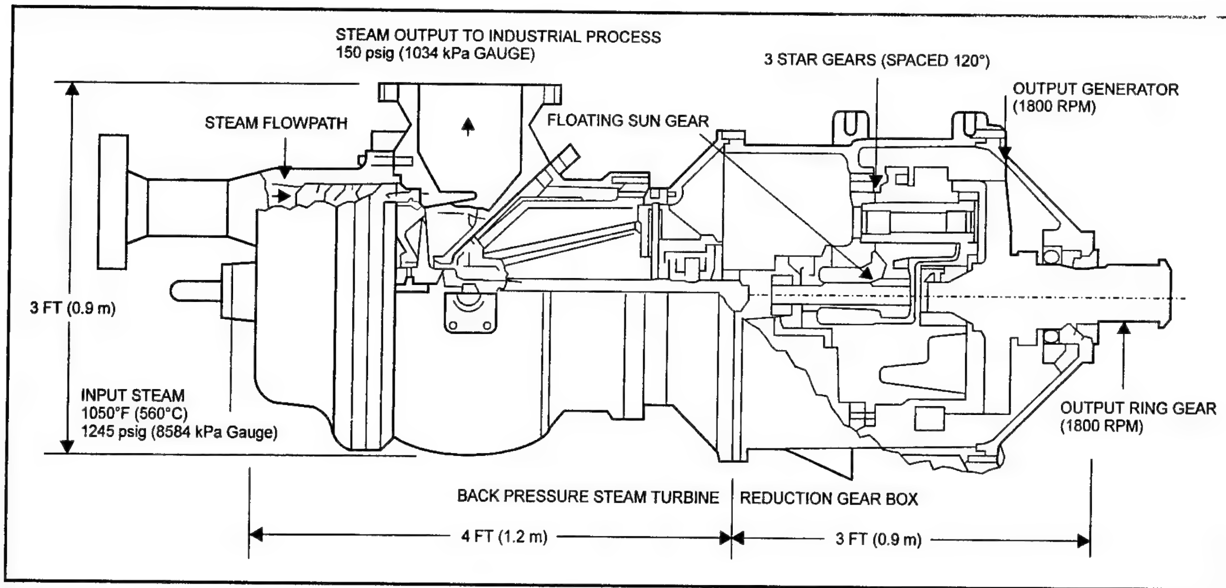
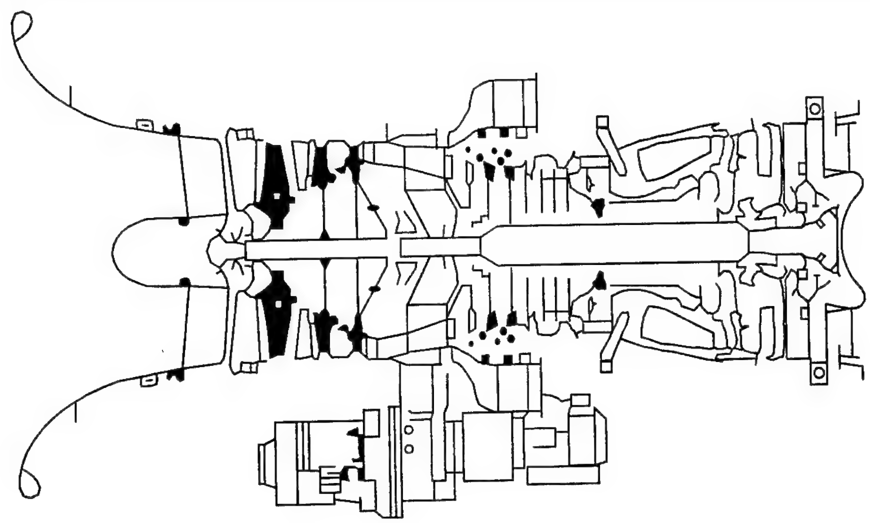


Figure 10. Solar Turbine's back-pressure steam turbine.

The system includes a matched set of skid-mounted subsystems consisting of a Solar Mars gas turbine/generator set with a Solar once-through HRSG and a newly designed two-stage, back-pressure, steam turbine/generator set. The modular construction and simplification of the steam generator and steam turbine results in a low capital cost, projected to be less than $600 to 700/kW. To further reduce costs, the steam/generator set uses many components already produced for its sister Centaur gas turbine/ generator set. The high efficiency of the steam turbine is due to its high temperature and high pressure operation, advanced materials, and high rotational speed (30,000 rpm). Variable thermal (up to 109,000 lb of steam at 100 to 250 psi) and electrical outputs (8.6 to 13.4 MW) provide greater flexibility to accommodate fluctuating loads. An optional condensing steam turbine can be added to the system to convert the process steam to electricity for a total system output of 22 MW. The advanced combined-cycle system also offers unattended operation and low emissions. Full-scale testing began in 1991, and the systems are expected to be commercially available in 1993.

General Electric Co. LM1600 STIG System

GE is currently developing a steam-injected gas turbine based on the GE LM1600, which is an available, easily maintained, and fuel-efficient turbine. The excess steam not required for process applications is recirculated into the turbine at 100 to 300 psi, which can reduce fuel consumption by up to 20 percent or can increase the electric output from 13.5 to 17.9 MW. Figure 11 shows a comparison of the LM1600 performance of a simple cycle and a STIG configuration.



PERFORMANCE	SIMPLE CYCLE	STIG (Approx.)
RATING	18,750 shp 13,500 kW	24,120 shp 17,900 kW
THERMAL EFFICIENCY	37 percent	42 percent
AIR FLOW	100 lb/sec	103 lb/sec
PRESSURE RATIO	22 TO 1	23 TO 1
EXHAUST TEMPERATURE	880°F	811°F
POWER TURBINE SPEED	7000 rpm	7000 rpm

Figure 11. Simple cycle and STIG performance of the LM1600 gas turbine.

A natural gas-fueled turbine with steam injection produces low levels of emissions. Current development is under way to minimize both NO_x and CO emissions and a prototype plant is planned for 1992. The steam-injected LM1600 has the potential to provide a cost-effective, efficient, flexible, and environmentally sound cogeneration system.

Allison 501-KH Gas Turbine STIG System

Field tests were conducted with the Allison 501-KH gas turbine to determine the performance of steam injection using industrial quality steam. Instead of the demineralizer used in current steam-injected system, a passive steam cleanup system was used to remove all contaminants and to reduce the expense and complexity of more conventional water treatments.

Field tests were concluded in July 1989 with an availability of 90.1 percent. The gas turbine/generator assembly produced 3.2 MW and 20,000 lb/hr process steam at 175 psig, which could be increased to 35,000 lb/hr with supplementary firing of the duct burner. In the steam injection mode, the generator output increased to 4.0 MW. The steam cleanup system reduced all nongaseous contaminants to below measurable

levels. NO_x emissions were lowered with steam injecting, yet this was accompanied by an increase in CO emissions. The use of a duct burner also significantly increased CO emissions, but did not affect NO_x level. Another company, European Gas Turbines, is also offering STIGs reported to increase turbine output by up to 20 percent, from 6 to 7.2 MW, with 11,000 lb/hr of steam.

Advancements in Gas Turbine Design

Two types of turbines used for electric generation are the aeroderivative turbine and the industrial (heavy-duty) turbine. The aeroderivative design was originally developed for aircraft applications. The industrial design is also based on aircraft engine technology, but incorporates steam turbine construction features. The two types differ in weight, maintenance, operating conditions, and performance.

The industrial combustion turbine has a heavier design and generally requires a larger foundation and more space. Aeroderivative machines have roller and ball bearings and use only a 50 to 200-gal lube oil reservoir. Industrial turbines have journal bearings that require a separate oil storage and cleanup system with a 1500 to 2500-gal oil reservoir. Due to the difference in weight, maintenance of each type also differs. The industrial turbines are designed to be maintained and repaired in place, whereas the lighter aeroderivative engines are more easily moved and usually can be changed out. Since the aeroderivatives require specialized materials for compactness and lighter weight, they are typically more expensive than industrial turbines.

The aeroderivative turbines can achieve full load in only a few minutes, while an industrial turbine requires 10 to 20 minutes. Likewise, cool-down time is longer for industrial machines, requiring 24 to 48 hours compared to the 3 to 5 hours for aeroderivatives. Aeroderivative engines operate with higher rotor tip speed, which requires better balance, but also allows for lighter weight components than industrial turbines. Aeroderivatives have higher pressure ratios, which provide high power output, but may require more service. Aeroderivative turbines have one annular space for combustion while industrial turbines usually consist of multiple combustors.

The performance of gas turbines has improved due to higher firing temperatures, better materials, and improved cooling techniques. Research in gas turbine design involves developing ceramics and composite materials for hot-section components and turbine blade coatings for higher operating temperatures and improved durability.

General Electric Aeroderivative Turbine

General Electric is currently testing the LM6000, a derivative of the GE CF6-80C2 aircraft engine. The 40 MW LM6000 is expected to be one of the most efficient simple-cycle gas turbines, yielding over 42 percent thermal efficiency. Hitachi, Ltd. has developed the H-25, a 25 MW gas turbine with a thermal efficiency of 32.6 percent (LHV) in simple cycle. It also has demonstrated high efficiencies in combined cycle or cogeneration applications. The H-25 is currently being field tested. Fourteen MW scale models of the H-25, the H-14/H-15, are also being developed.

Kawasaki Heavy Industries Gas Turbines

Kawasaki Heavy Industries (KHI) in Japan has recently introduced the M1A-23, a 2 MW natural gas-fueled turbine designed for both simple-cycle and heat recovery applications, with a 25.9 percent simple cycle thermal efficiency and a heat rate of 12,170 Btu/kW. The firing temperature of 2100 °F is the highest of the KHI turbine line. An exhaust temperature of 1100 °F is reported at base load. The available standard reduction gear can drive 50 or 60 Hz generators. A twin version of the M1A-23 is also currently available; the 4 MW M1T-23 consists of two gas turbines with a single gearbox.

Westinghouse Electric Corp. Gas Turbine

Westinghouse Electric Corporation is involved in a development program for a dual-fuel, dry, low NO_x combustor. The goal of the project is to reduce NO_x emissions without using water and steam injection techniques. The low emission combustor will be designed for use with the full range of Westinghouse combustion turbines. Field testing of the combustor modules is planned for the near future.

Advanced gas turbine designs are also expected from Pratt & Whitney, and Rolls Royce. Other manufacturers of gas turbines under 20 MW include Allison, ASEA Brown Boveri, Dresser Rand, Ruston, and Solar Turbines. In addition, Westinghouse Electric, FiatAvio of Italy, and Japan's Mitsubishi Heavy Industries have recently signed a 10-year agreement to cooperate in the development, manufacturing, and marketing of gas turbine technology.

Advanced Coal-Fueled Turbines

Due to the large supply of domestic coal, coal-based power plants offer a low cost alternative in the event of a shortage or price increase of oil and/or natural gas.

Currently, due to economies of scale, most coal-fired technologies are cost-effective for only large scale applications. Since coal plants involve high capital costs, large plants with a high annual capacity are generally the best applications for this technology.

The emphasis of current research is on the development of Clean Coal Technology (CCT). This involves control of NO_x and SO_2 emissions through precombustion coal cleaning, advanced coal combustion technology, or postcombustion environmental controls. Cogeneration systems using pressurized fluidized-bed combustion (PFBC), humid air turbine (HAT), and integrated gasification combined cycle (IGCC) are usually employed for plants larger than 150 MW.

Development in coal-fueled heat engine technology focuses primarily on improving efficiency, durability, and minimizing emissions. Coal-fueled engines could potentially offer more efficient, cleaner, and lower-cost options for power generation. Current research includes the development of direct coal-fueled diesel engines, gas turbines, and the indirect gas turbine cycle. Coal-fueled Diesel engines are discussed below.

Indirect-Fired Gas Turbine

In an ordinary gas turbine, the pressurized gas leaving the compressor is heated by internal combustion before entering the turbine. The indirect-fired gas turbine uses a heat exchanger, instead of a combustion chamber, to increase the temperature of the pressurized air flowing between the compressor and the turbine. Since the combustion products do not go through the turbine, the indirect-fired concept permits the direct use of coal, wood, or other low-cost, high-ash fuels that would foul an ordinary gas turbine. The indirect gas turbine technology eliminates the problems involved in coal burning by the use of an externally fired ceramic heater.

In the closed-cycle (Figure 12) separate air streams are used for the turbo-machinery and for the combustion. Ten closed cycle plants, from 2 to 30 MW, were operated from 1956 to 1975 in Germany, Japan, Russia, and Austria. Service lives up to 100,000 hours were reported. Turbine inlet temperatures could not exceed 1200 to 1400 °F due to the material limitations of the metal heat exchangers. Plant efficiency rates of 25 to 31 percent were achieved with extensive intercooling, recuperation, and precooling, yet this required very high capital costs.

Another approach is referred to as an exhaust-fired gas turbine, which is an open cycle and eliminates the precooler, the intercoolers, and the separate air combustion system. A heat exchanger (Figure 13) raises the temperature of the air entering the turbine.

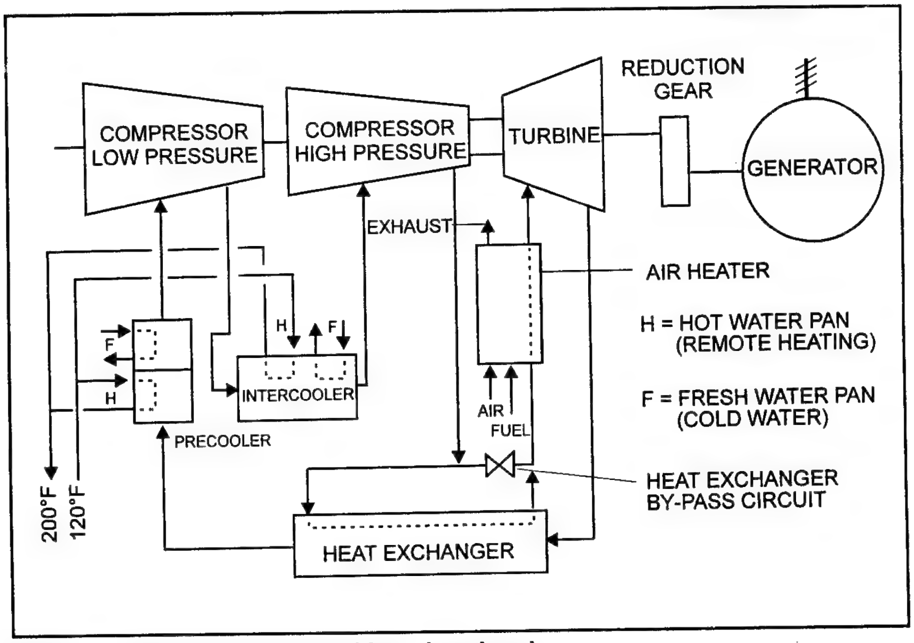


Figure 12. Indirect-fired gas turbine, closed cycle.

The turbine exhaust is then used as combustion air and provides hot gas to the heat exchanger. For additional power and efficiency, a heat-recovery steam generator increases the temperature of the hot gas and the resulting steam is injected upstream of the heat exchanger. To further increase the system efficiency, the steam can be expanded through a steam turbine before entering the heat exchanger.

The performance of indirect-fired gas turbines is limited due to the materials of the heat-exchanger. Currently, heat-exchanger metals have a maximum temperature of

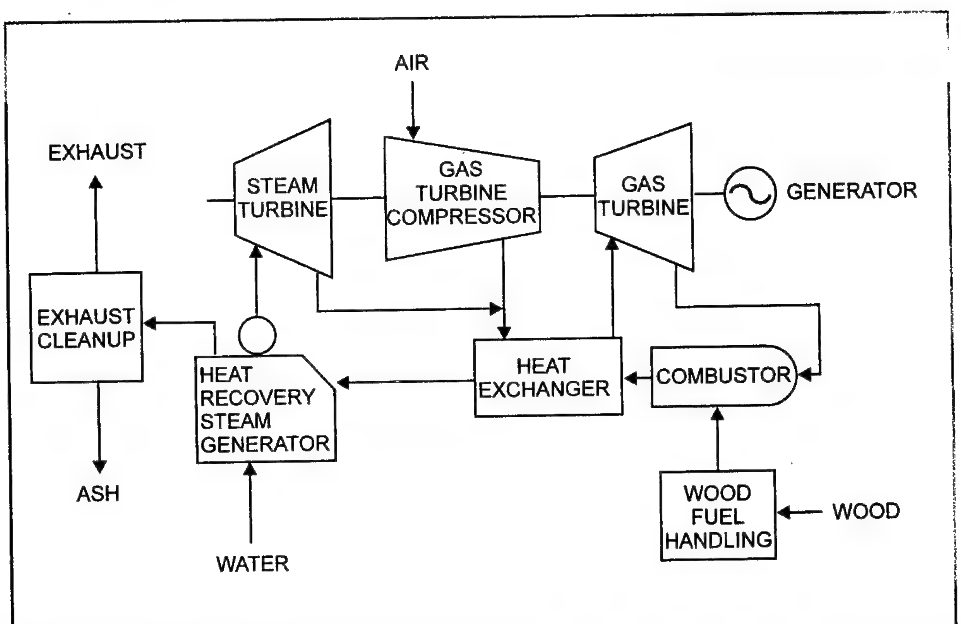


Figure 13. Indirect-fired gas turbine, open cycle.

1500 °F which result in a maximum turbine inlet temperature of 1450 °F, compared to the 1700 to 2300 °F of direct-fired turbines. Research is continuing on ceramic heat exchangers that could allow turbine inlet temperatures of over 2000 °F. At this temperature, the cycle efficiency is projected to be greater than 40 percent, which would significantly improve the system's economics. With the development of advanced materials to improve performance and reduce capital costs, the indirect-fired gas turbine is a promising concept that can use low-cost, high-ash fuels, including coal.

Allison's Advanced Coal-Fueled Gas Turbine

Allison has developed bench-scale and full-scale components required for engine testing on coal water slurry (CWS) fuel. The scope of the project includes coal fuel availability, cost, handling, and delivery systems; combustion performance; and sulfur, NO_x, and CO emission control. An Allison 501-KB5 industrial gas turbine was modified to accept an external combustion system and is now being tested on CWS fuel. Goals for coal-fueled gas turbine system include an ash management system for turbine durability, acceptable maintenance intervals, and control of particulate rates.

Solar Turbine's Coal-Fueled Gas Turbine

Solar Turbine's development of a coal-fueled gas turbine system is based on its 3.8 MW gas turbine model, the Centaur Type "H" engine. A coal/water mixture is directly fired in a two-stage slagging combustor. This work includes development of the combustor, cleanup system, fuel specification, a hot end simulation rig test, and system modeling. Solar's approach includes applying advance technology to solve problems such as deposition, erosion, and hot end corrosion, and to comply with environmental constraints on NO_x, SO_x, and particulates. The final goal is to bring the coal-fueled gas turbine technology to full commercialization. The last stage of the current project involves integration of developed components into a final system design followed by extended verification testing and collection of performance data.

Engine-Driven Reciprocating Engine

Diesel and spark ignition reciprocating engines are available in sizes from a few HP to nearly 50,000 HP. Speeds vary from about 50 to more than 4,000 rpm. In general, as speeds increase, the engine costs less per unit output, and has lower efficiency and higher maintenance costs. Typical heat rates for reciprocating engines are 8,000 to

11,000 BTU per kWh. This means that a typical efficiency is on the order of 25 to 50 percent. Typically, one-third of the energy lost in a reciprocating engine is from the exhaust at about 800 °F and the remainder is lost in lube oil and cooling water at approximately 200 to 300 °F. Slow-speed Diesels have run as long as 10 years without a major overhaul. However, at engine speeds in excess of 2,000 rpm, the engine life may be less than 1 year. This is a major factor to consider in the economics of this type cogeneration. Tables 6 and 7 list some characteristics of reciprocating engines.

Figure 14 shows mechanical efficiency for reciprocating engines, gas, and steam turbines. For the sizes of interest for DOD cogeneration applications, reciprocating engines can produce more mechanical work, and therefore more electricity per unit of input fuel than either of the other options. Figure 15 shows the approximate heat rates for low, medium, and high speed Diesel engines, indicating that typically mechanical efficiency (and therefore electrical efficiency) increases as the engine operating speed class decreases. This figure also indicates the engine attains its highest efficiency when operated at about 80 percent of rated capacity.

Gas Engine-Driven Packaged Cogeneration

Tecogen Peakshaving/Baseload Cogeneration System

Tecogen, Inc. has developed a peakshaving twin-engine cogeneration system designed to double its speed and output during peak loads to reduce the use of expensive utility peak electricity. The system consists of two automotive engines designed for high speed operation, priced at a fraction of the cost of industrial-grade engines. Engine life is extended by limited periods of peakshaving operation. A microprocessor control system provides on-site or remote operation and enables automatic switching between peakshaving and baseload operation. Due to lower capital costs and the peakshaving feature, Tecogen claims that this unit has a better payback than conventional cogeneration systems in most areas of the country.

Baseload power of 160 kW is supplied at 1800 rpm with a peak load of 320 kW at 3600 rpm and heat recovery of 1 to 2 MBTU/hr. The system has a projected electrical and overall thermal efficiency of 29.2 and 82.8 percent, respectively, and a 26 percent electrical efficiency in peakshaving operation. The physical size of the system is 10.5 ft x 7 ft, 6-ft high, and it weighs 10,000 lbs. Field experiments were conducted with Baltimore Gas and Electric Co. at a Maryland hotel. Several prototype units were field testing in 1992.

Table 6. Reciprocating engine characteristics.

Types*		Size			Thermal Output	
Spark-Ignited	Diesel	Low Speed	Medium Speed	High Speed	Source	Quality
• Gaseous fueled • Medium, high speed • 7:1 to 10:1 compression ratio	• Wide range of fuels • Low, medium, high speed • 15:1 compression ratio	• 50 to 300 RPM • 35 to 50% efficiency • 1500 kW to 40,000 kW	• 300 to 900 RPM • 30 to 40% efficiency • 700 to 10,000 kW	• Over 900 RPM • 25 to 35% efficiency • 15 to 1,000 kW	• Water jacket • Exhaust • Lube oil cooler • Turbocharger cooler	• Hot water 180 to 250 °F • 15 psi steam
*Gas and Diesel engines unless otherwise noted						

Table 7. Diesel engine operation/maintenance requirements.

Component	Time Between Overhauls
Cylinder liner	100,000 hours
Exhaust valves	12,000 to 20,000 hours
Pistons	12,000 to 20,000 hours
Injection nozzles	8,000 to 20,000 hours
Cost: 0.7 cents/kwh to 1.5 cents/kwh	

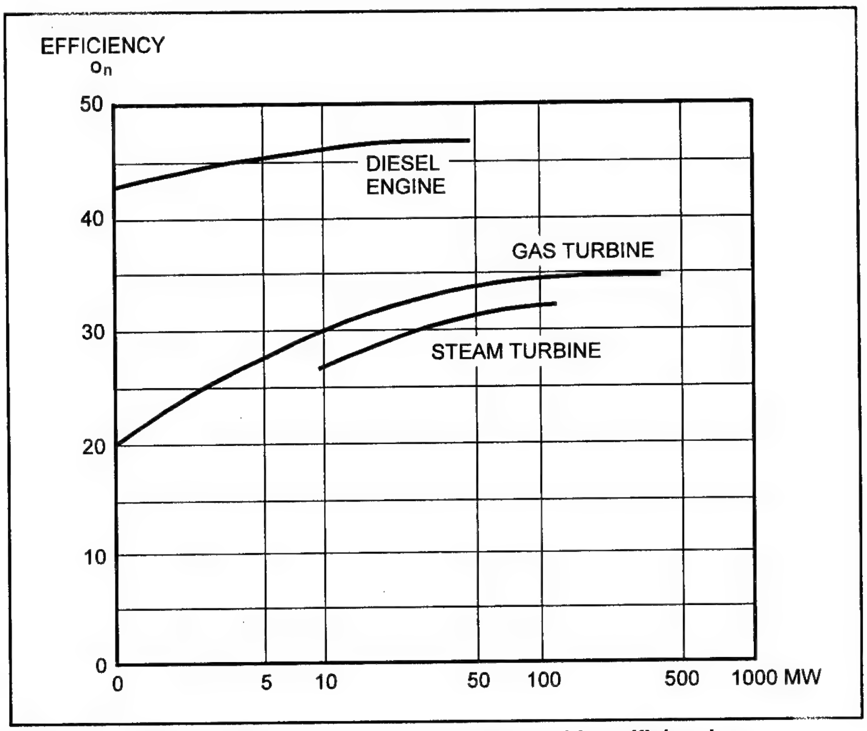


Figure 14. Reciprocating engine gas and steam turbine efficiencies.

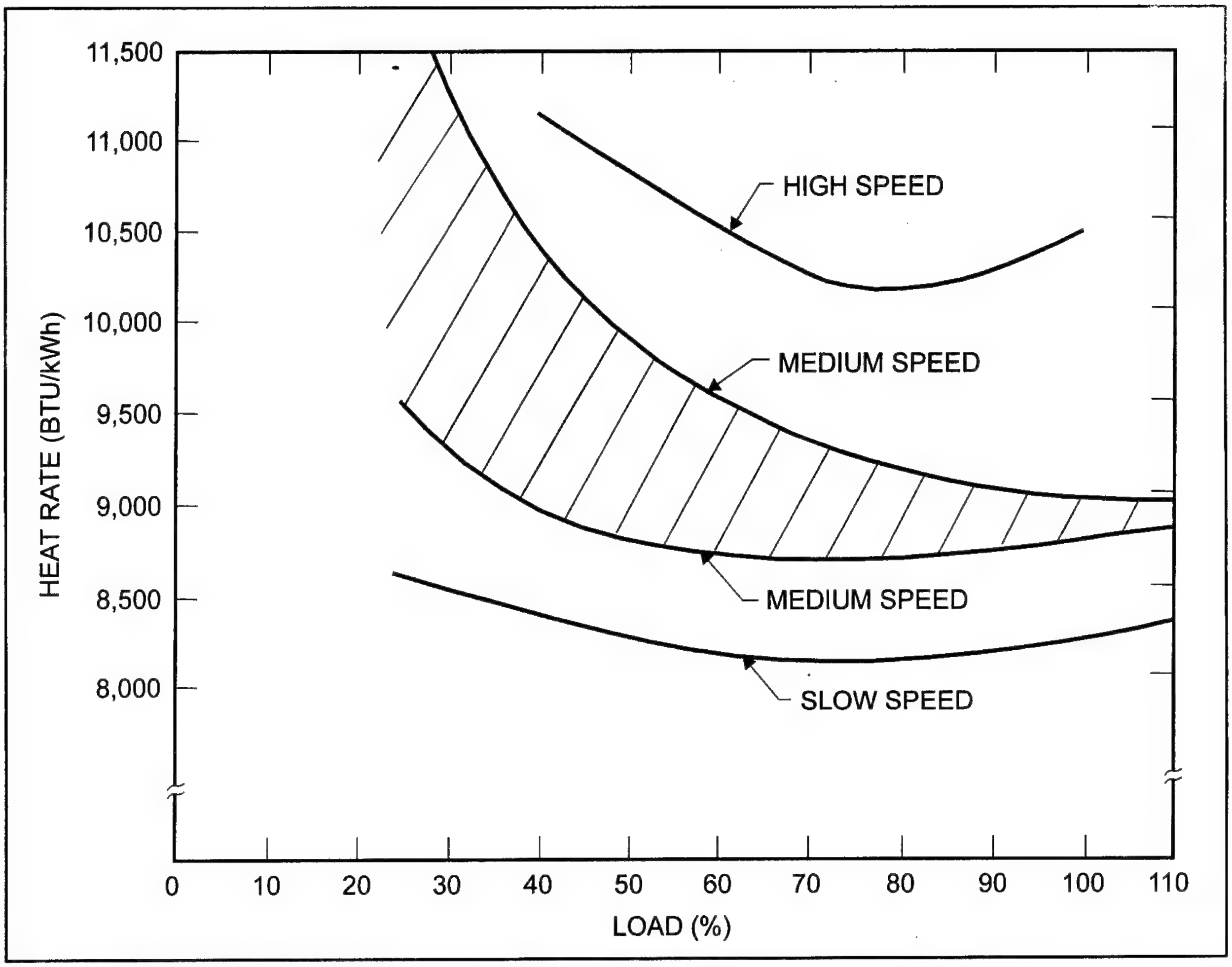


Figure 15. Typical variation of diesel heat rate with load.

Tecogen Engine-Driven Cogeneration Systems

Tecogen has developed a 600-kW unit that produces low pressure steam and variable amounts of electricity. Waste heat from the engine's cooling jacket is compressed to 85 to 125 psig steam. This system offers added flexibility by controlling the use of the compressor to provide the option of low pressure steam or additional electricity as needed. For example, during winter months, the system can provide low pressure steam for space heating and hot water. During the summer, the unit can generate the maximum electricity to offset peak utility charges and the low pressure steam can be used for hot water and absorption cooling.

The system consists of a natural gas-fueled engine-generator set (Caterpillar G399TC) and a twin helical screw compressor (Atlas Copco ZA4). Programmable controls require minimal attention from operators. With the use of the compressor, the unit can deliver 300 lb/hr of 1100 psig steam and 450 kW. During low heating demand, 565 kW can be produced with 1100 lb/hr of 100 psig steam and 1750 lb/hr of 15 psig steam.

In addition, using waste heat from the engine's cooling jacket and other sources increases the system's overall efficiency to 74 percent as opposed to the 45 percent reported by conventional systems using only exhaust heat. Field tests of the Tecogen 600 kW cogeneration system have been conducted beginning in 1989.

Tecogen also offers a series of engine-driven packaged cogeneration systems. The CM-30i is a 30 kW cogeneration module designed from small and mid-sized commercial and industrial facilities. One or more modules can be installed up to 150 kW. The CM-60 and the CM-75 are also cogeneration modules with capacities of 60 kW and 72 kW, respectively. Due to their smaller size, these units would not be as suitable for centralized power generation on DOD bases, but could meet the needs of individual building or process thermal loads. Also, these smaller units could supply a part of the building's electric needs.

Advancements in Gas-Fueled Engine Design

Reciprocating Engines

Most large gas-fueled engines are based on heavy-duty diesel engine design. To accommodate natural gas, modifications must be made to the engine to include a lower compression ratio, spark ignition, and a carburetor fuel system. While gas-fueled engines are less efficient than the diesel engines, the clean burning natural gas improves engine durability, making gas engines an excellent alternative for continuous duty applications like cogeneration.

Development in natural gas-fueled engines focuses on improving performance, reducing costs, and lowering emissions. "Lean-burn" is a technique in which the engine operates with more air than is required for combustion. This reduces the detonation tendency of natural gas, produces higher compression ratios and increased power, and reduces emissions. Waukesha Engine Division of Dresser Industries is developing a small precombustion chamber where a rich natural gas/air mixture is burned. The chamber is used to ignite the lean mixture in the engine cylinder. This low-cost engine is expected to improve efficiency by 33 percent and lower emissions by 90 percent without a catalytic converter.

For smaller engines (350 to 700 HP), Caterpillar is developing a "fast-burn" technique that improves combustion by creating high levels of turbulence inside the combustion chamber. The fast burn concept is also expected to increase efficiency by 33 percent and provide a 90 percent reduction in emissions.

Other techniques, such as direct-injection of natural gas and the use of glow plugs, can also improve engine performance. Another approach to improve engine performance is the development and application of advanced materials. The use of ceramic components, for example, a ceramic-insulated precombustion chamber to increase temperature and improve natural gas combustion, will allow for hotter operation and the recovery of higher temperature heat.

Rotary Engines

Although less developed than reciprocating engines, rotary engines offer many advantages. Based on Felix Wenkel's 1954 design, rotary engines are smaller and lighter than reciprocating engines. With no valves or connecting rods, the simple design provides high power density, potentially low manufacturing costs and low maintenance. The rotary engines have a potential market in applications such as heat pumps, refrigeration, cogeneration systems, water pumping and as replacements for electric motors for industrial fans. To be competitive, the lifetime of the rotary engine must increase from 2000 to 20,000 hours and efficiency must improve from 25 percent (HHV) while overcoming wear, low efficiency, and high emissions problems.

Stirling Engines

Invented in 1816, the Stirling engine (Figure 16) was used throughout the 19th century until the development of the diesel and piston engines. Unlike other engines, combustion occurs in the Stirling engine outside the working space of the engine. The design eliminated valves and separated the lubricating oil from the combustion products, so the Stirling engine design has fewer moving parts than other heat engines and

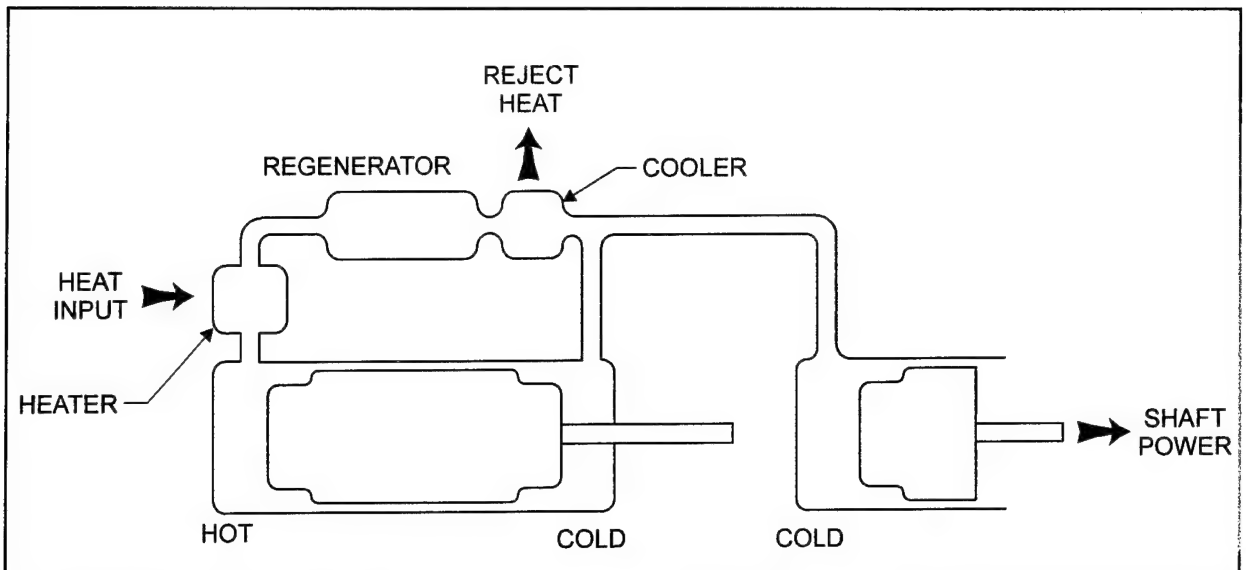


Figure 16. Simplified Stirling cycle.

very low maintenance requirements. The Stirling engine also has a high theoretical efficiency and lower emissions and noise levels than any other engine designs.

The main moving components of the Stirling cycle are a displacer piston and a power piston. These parts, along with a high-temperature heated zone, a low-temperature cooled zone, and the working fluid (usually hydrogen or helium gas) are all that are required to build a basic Stirling cycle engine. To operate the engine, the displacer piston moves back and forth causing the working fluid to be alternately moved to and from the heated and cooled sections of the engine. As the gas in the high-temperature region is heated, its pressure increases to a level high enough to move the power piston in the power stroke. At the end of this stroke the displacer piston is shifted, moving the working fluid into the cooled region where its pressure is reduced, allowing the power piston return stroke to occur. This alternate heating and cooling of the closed system allows the cycle to be repeated, generating continuous power output. The displacer piston is mechanically coupled to the power piston so the two pistons are always in the correct relative position to each other. Several piston/displacer units can be connected to create a smooth running engine with only one heat input section and one cooling section.

Because of high operating temperatures and pressures, together with materials problems and precise manufacturing tolerances, the Stirling engine has seen only limited commercial use. Current advances in material and manufacturing technologies may offer new solutions to these problems and have already encouraged further development. A Stirling engine-driven heat pump was developed in Japan and marketing of this product is planned for this year. Stirling Power Systems, in the United States, is also working on the commercialization and marketing of Stirling engines.

Advanced Coal-Fueled Engine Design

Arthur D. Little, Inc. / Cooper-Bessemer Coal-Fueled Engine

The Cooper-Bessemer "Proof-of-Concept" program involves the development and commercialization of a coal-burning heat engine for 2 to 50 MW modular stationary power applications. The system is based on the Cooper-Bessemer LSB engine (2 to 6 MW), which was modified for coal slurry fuel with heat recovery. This project addresses specific component problems such as injection nozzle erosion, wear of piston ring, exhaust valve, and turbocharger, low-cost emission control, and low-cost fuel cleaning. Component design, development, and testing will be followed by system testing and evaluation.

Generators

Generators convert the rotational mechanical energy of the prime mover into electrical energy. Engine-generator sets are available from a few Watts to multi-megawatt systems. Generators typically operate at 1200 or 1800 rpm. Reciprocating engine speed can be matched to the required generator speed, thus eliminating the added cost and slight inefficiency of a speed-reducing gearbox. Steam and gas turbines operate at much higher speeds and do require speed reduction between the turbine output and the generator input.

Generators produce electricity by rotating a coil through a magnetic field. There are two classifications of generators, based on how the magnetic field is created. Induction generators require an external source, such as the electric grid, to set up the magnetic field; synchronous generators, by contrast, are self-excited. Both types are suitable for cogeneration applications, but each has certain advantages. Factory-assembled systems may be purchased with either type generator. Both are available in a wide range of voltages to meet the specific needs of the user. The choice of a generator depends on cost, efficiency, voltage regulation, harmonics, and type of application.

Induction Generators

An induction generator is basically an electric motor driven at a slightly higher speed than it would operate if it were not loaded. As the shaft speed increases, so does the amount of electrical power generated. Since the generator field current is provided by an external source, normally the electric grid, the output will automatically be synchronized with that source.

Unless corrected, an induction generator will have a poor power factor because of the required reactive power needed for generator excitation. This problem can be easily corrected by adding a capacitor bank. This capacitance also allows for the possibility of transient operation of the generator without the need of external excitation, thus allowing for operation when power is lost from the utility grid. To maintain the standard frequency of 60 Hz needed by the electric loads to be operated by the generator, some form of frequency protection is also generally required.

Induction generators are inexpensive, compared to synchronous generators. Because they must be externally excited, they are also relatively inexpensive to interconnect to the electric utility grid. For these reasons, they are very popular in smaller cogeneration systems. The major disadvantage of induction generators is that they cannot operate in an isolated mode without an external excitation power source.

Synchronous Generators

Synchronous generators provide their own excitation and can be operated in isolation from the utility grid. This type of generator is typically used in emergency power applications. When operated in isolation from the utility grid, precise speed control of the prime mover is required to maintain the desired frequency. When a synchronous generator is to be interconnected to the utility grid, the cogeneration system must provide some means to synchronize the generator's voltage, frequency, and phase angle with those of the utility grid prior to grid connection. Once the cogeneration system and the grid are interconnected, the generator frequency will be controlled by the grid.

Heat Extraction Equipment

To be classified as a cogeneration system, two forms of useful energy (typically, electricity and thermal energy) must be derived from a single energy source. To collect the thermal energy in a useful form, this system requires heat exchangers (HX) in which air or water is heated, steam is generated, or some combination of these processes takes place. Heat transferred to the cooling fluid is carried to a thermal load or, if excess thermal energy is being produced, some may be rejected to the atmosphere. Rejecting thermal energy will typically occur only a very small fraction of the operating time, if at all, although provisions are often made to allow operation of the electrical generation portion of the system when the thermal side is down for maintenance or repair.

Heat extraction typically occurs in shell-and-tube or plate-and-frame heat exchangers, in heat recovery steam generators (HRSG), or directly, as in an ebulliently cooled engine. Shell and tube heat exchangers have traditionally been the primary method of heat recovery. Due to their compact size, high performance, ease of maintenance, and moderate cost, plate and frame HX are becoming quite popular for applications where small approach temperatures are required.

Heat from a reciprocating engine can be recovered from several different subsystems, each at different temperatures. These include the lubricating oil, water jacket, and exhaust. Table 8 shows typical temperature ranges

Table 8. Heat recovery for reciprocating engines.

	Temperature (°F)	Thermal Energy (Btuh/hp)
Oil cooler	150 – 180	~ 300
Water jacket	210 – 225	~ 2,700
Exhaust gas	300 – 425	~ 1,400
Ebulliently cooled engine	15 psi steam	

for each of these areas. Figure 17 shows how the input energy is divided between mechanical work and heat energy.

An HRSG is often used in conjunction with a gas turbine. In an HRSG, the hot (about 900 to 1100 °F) turbine exhaust gas is used to generate steam. An HRSG is typically somewhat larger and more expensive than a conventional boiler with the same nameplate rating. This is because the conventional boiler relies heavily on radiant heating in the boiler for a significant part of the heat transfer because conventional boilers have higher flame temperatures than HRSGs, which instead rely much more on convection heat transfer and require larger heat transfer areas, two characteristics that increase size and cost.

When a large thermal load exists or when high-pressure steam in required, the temperature of the exhaust gas can be increased by adding fuel and allowing combustion to take place before the gas enters the HRSG. This process is very efficient as the turbine exhaust gas typically contains approximately 16 percent unreacted oxygen and is already at a high temperature. This process can also be an efficient way to

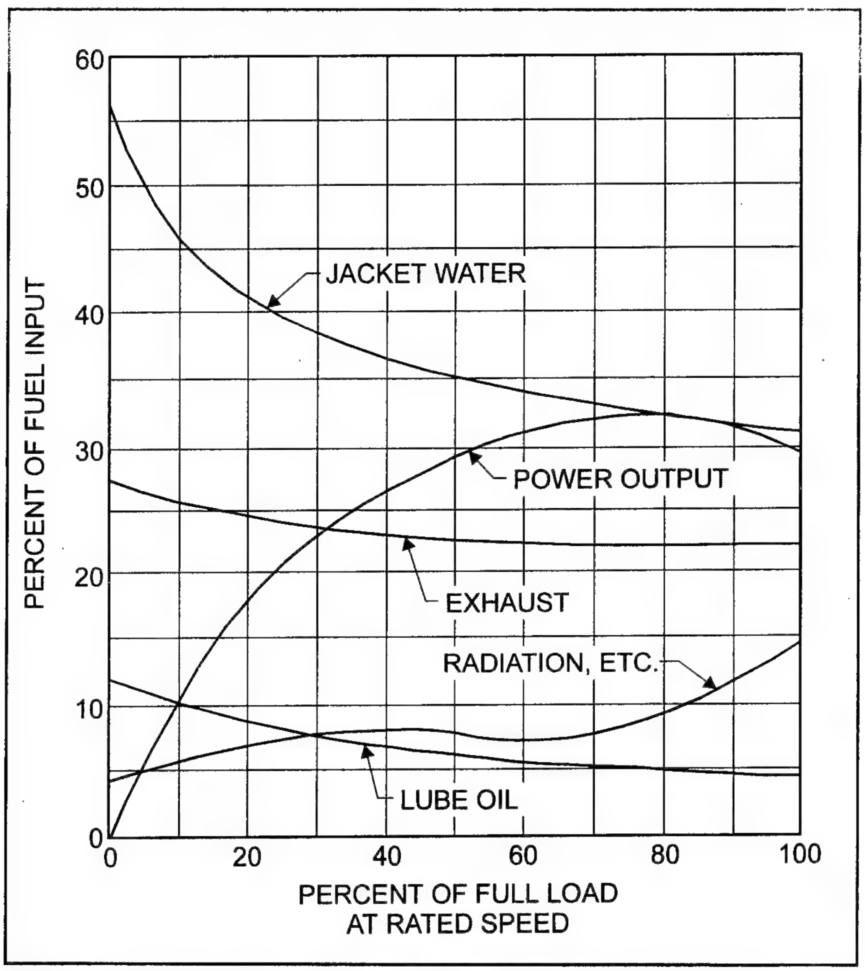


Figure 17. Heat balance for typical naturally aspirated engine with water-cooled exhaust manifold.

control the thermal energy output while maintaining a constant electrical output. When additional steam is required, this method is highly recommended.

Absorption Chiller/Heaters

Absorption cooling systems are heat-operated refrigeration systems that use pumps, heat exchangers, and pressure vessels in place of the compressor used in conventional mechanical vapor compression refrigeration systems. In mechanical refrigeration systems, a fluid vapor is compressed and the latent heat is removed by a condenser. The fluid then flows through an expansion valve to an evaporator at a lower pressure. As the liquid evaporates and expands, because of the lower evaporator pressure, it absorbs the surrounding heat. The cycle is completed as the vapor returns to the compressor.

Figure 18 shows the main components of a single-effect absorption cycle. Commercially available absorption cooling systems generally use lithium bromide (LiBr) as the absorbent and water as the refrigerant and operate in a vacuum. Figure 18 shows the stepped process: the absorption process cools by spraying liquid refrigerant into the evaporator (1), where it evaporates, absorbing heat from the warm water in the loop. The refrigerant vapor from the evaporator is absorbed by a concentrated solution of the absorbent (LiBr) with a strong affinity for the refrigerant (water) in the absorber (2). This process creates a vacuum, which causes the refrigerant to evaporate at a low temperature. As the concentrated solution absorbs more refrigerant, its affinity for the refrigerant becomes weaker. The resulting weaker solution is pumped to the generator (3). In the generator, heat is added, driving off the refrigerant and reconcentrating the LiBr solution. The concentrated LiBr again has a strong affinity for the refrigerant and is pumped back into the absorber. A liquid-to-liquid heat exchanger

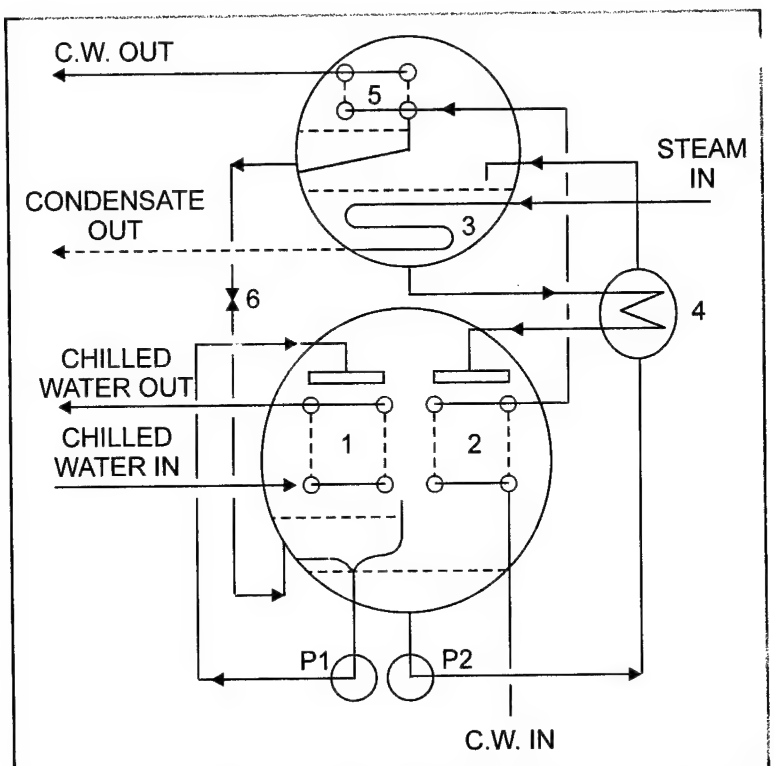


Figure 18. Single-effect absorption chiller.

(4) is typically used to recover heat from the strong solution returning to the absorber, preheating the weak solution before it enters the generator. The hot refrigerant vapor that is released from solution in the generator is cooled and condensed to a liquid in the condenser (5). It then passes through an expansion valve (6) and again enters the evaporator.

Double-effect absorption chillers recover the waste heat in the system and use it in a second refrigeration stage (Figure 19). This increases the system efficiency by 40 percent over conventional single-effect chillers. Double-effect LiBr absorption chillers can have a coefficient of performance (COP) up to about 1.15 compared to the 0.8 COP for single-effect units. This technology can be applied to chillers ranging in capacity from 100 to over 1000 tons.

Absorption chillers can recover low-grade industrial waste heat from cogeneration or process steam and produce chilled water. Absorption cooling provides air-conditioning without the use of chlorofluorocarbons (CFCs). In addition, the relatively low number of moving parts makes absorption coolers very reliable. Absorption systems are cost effective; their high capital costs are offset by the difference in the cost of heat required compared to the cost of electrical power needed to drive a mechanical refrigeration system. Thus, absorption chillers provide an efficient and environmentally safe alternative for space cooling, especially in cogeneration applications with an available heat source.

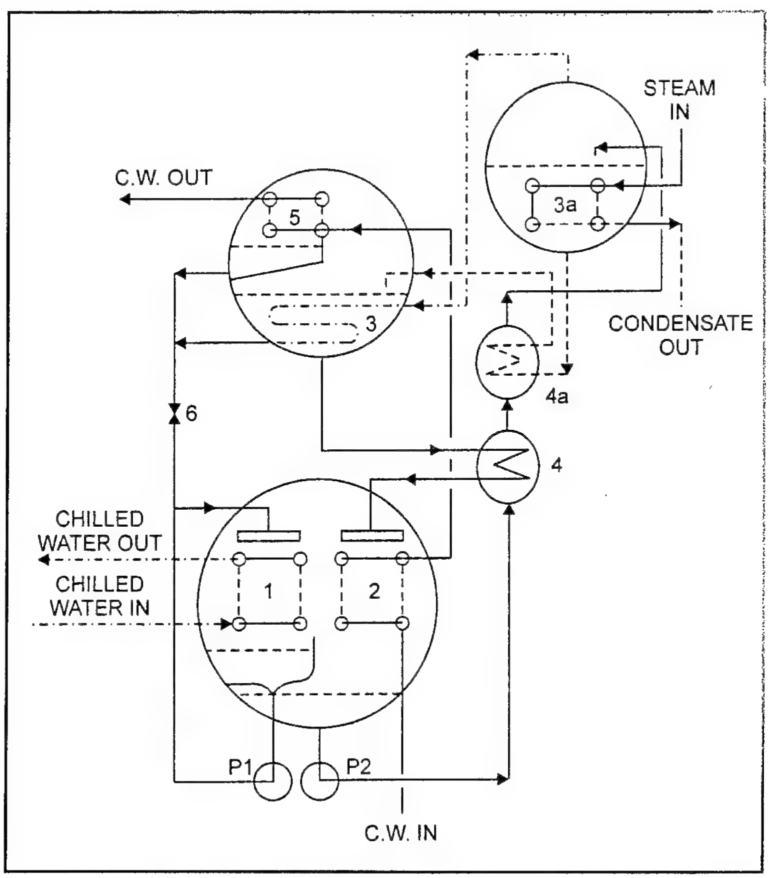


Figure 19. Double-effect absorption chiller.

The performance of the absorption system depends on the solubility of the refrigerant in the absorbent and the differences in their boiling points. Two commonly used refrigerant/absorbent fluids are lithium bromide/water and ammonia/water. Lithium bromide systems can be used in single-stage or two-stage units but are not practical for chilled-water temperatures less than 42 °F. Single stage units range from 100 to

1650 tons and use low pressure steam (15 psig) or hot water. Double-effect absorption chillers typically have a capacity less than 1500 tons, and require steam pressures of about 120 psig. While these chillers require a higher grade of thermal energy, they use about 40 percent less steam per unit of cooling than a single-stage chiller. Costs are estimated at $250/ton for single-stage and $330/ton for two- stage units. Ammonia/water systems operate between 40 and 50 °F, but require steam pressures of 175 to 265 psig and are also much larger. The cost of these systems is approximately $650/ton.

Advanced Absorption Cooling Technologies

Trane Direct-Fired Double Effect Absorption Chillers

Trane currently offers a complete line of direct-fired absorption chillers with capacities of 100 to 1100 tons available in standard efficiency (COP = 1.0, HHV) and high efficiency (COP = 1.07, HHV) models capable of providing simultaneous heating and cooling.

Trane is also developing a microprocessor control system, expected to be commercially available in 1993, to simplify the operation of conventional absorption chillers.

Carrier Double-Effect Absorption Chiller

The 200-ton double-effect Carrier chiller has a COP of 1.0 and is designed for use in large commercial buildings. The unit can also be used for space heating and hot water. The Carrier unit is economical and highly reliable, requires minimal maintenance, and gives quiet, vibration-free operation. This double-effect chiller is expected to be commercially available in the near future.

York International Corp. / Hitachi

York International Corp. is developing advancements in controls, hardware, and burners for the complete line of Hitachi absorption chiller/heaters ranging in size from 40 to 1500 tons. York ParaFlow lithium bromide/water absorption chillers use two-stage technology to increase cooling efficiency by about 40 percent. These units can operate on gas, propane, oil, exhaust heat, or steam and can save up to 50 percent on operating costs. Over 450 ParaFlow chillers have been sold for commercial and industrial applications. These units are unique in that they can use direct-fired natural gas burners as the heat source.

State-of-the-Art Triple-Effect Absorption Chillers

There is also interest in the development of a triple-effect absorption chiller for large commercial and institutional applications. The triple-effect technology, based on the same concepts as the double-effect chillers, is expected to achieve a coefficient of performance of 1.5 and an increase in efficiency of 50 percent over state-of-the-art double-effect absorption chillers. Current development involves identifying materials with the desired corrosion-resistant properties and an environmentally acceptable absorption fluid and refrigerant. Recently, a 190-ton prototype triple-effect absorption chiller was constructed and is currently under evaluation. Field tests are planned for 1993 or 1994.

Cogeneration System Controls

Like most mechanical systems, cogeneration plants require controls to assure safe operating conditions and maintain high system efficiency. Control systems may range from a single display panel mounted directly on a small cogeneration system, to a large control room, completely enclosed for the protection of the operators and sophisticated computer monitoring equipment, on large systems. Both types of control systems maintain safe and efficient operating conditions. Table 9 lists a number of typically monitored operating variables.

Systems may be monitored on-site by the system user, or remotely via telephone modem by a service company under contract to provide monitoring and maintenance for the cogeneration system. Both onsite and remotely monitored systems have benefits. An onsite-monitored system allows monitoring to become an element in the daily schedule for maintenance personnel. Remotely monitored systems use trained experts who deal with cogeneration daily to periodically monitor operation. The choice between these options depends on how involved the owner wishes to be in the day-to-day systems operation.

Table 9. Monitored variables for cogeneration systems.

General System Status	Electrical Subsystem	Prime Mover
Date and time	Power	Engine speed
Run time	Voltage	Oil temperature
Over limit alarms	Voltage phase angle	Oil pressure
System status	Power factor	Coolant temperature
Number of starts	Line frequency	Exhaust temperature
	Current	Air temperature
	Current phase angle	

Gas Engine-Driven Cooling Systems

Most gas-fired, engine-driven cooling systems are essentially conventional vapor compression chillers in which the electric motor is replaced by an internal combustion engine, typically fueled by natural gas. Some minor modifications in compressor operation and drive mechanisms are also generally required. While electric motors have high durability and low maintenance requirements, advancements in design and material are making gas engines a competitive alternative. Unlike constant-speed electric motors, gas engines have the flexibility of adjusting engine speed to the cooling load to improve efficiency. In addition, the heat produced by the gas engine can be used for domestic water, space, or other process heating.

Engine-driven chillers range in capacity from 15 to over 1000 tons and are available in a wide range of capacities. COPs range from about 1.0 to over 2.0 depending on system configuration and whether or not the thermal energy is recovered.

Two different approaches have been taken as to engine type: modified, automotive derivative engines vs. industrial engines. Both have benefits. Automotive derivative engines are manufactured in high production volumes at a considerably lower cost than industrial engines. On the other hand, the expected life of the industrial engine is two to four times longer than the automotive-type engines. When the industrial engine has reached the end of its useful life, it can typically be overhauled many times before the entire engine must be replaced. This is less likely to be the case with the automotive derivative engine. Minor maintenance is similar for both engine types.

Alturdyne Energy Systems Engine-Driven Chillers

Alturdyne Energy Systems has developed a line of engine-driven chillers ranging in capacity from 25 to 1100 tons. These systems use industrial engines to drive reciprocating and screw-type chillers. Systems are available as water chillers or direct expansion units with air, water, or evaporative-cooled condensers. Full load system performance, depending on chiller size and condenser type, range from COPs of 1.4 to 2.08 and can provide up to 4.1 MBTU/hr hot water to meet thermal energy requirements. Due to the variable speed operation of the engine, the chillers can achieve high part-load efficiency with excellent load following capabilities.

Tecochill Engine-Driven Chillers

Tecochill has developed a line of 125 to 500-ton gas engine-driven chillers. The smaller systems were designed around replacing the electric motors with automotive derivative engines modified for natural gas. While automotive engines are not as durable as

industrial engines, they are considerably less expensive in part due to high volume production. The new version of the larger chillers use industrial engines as their prime mover. Tecochill is also planning to manufacture chillers up to 750 tons starting in 1994.

The 500-ton chiller has a full load COP of 1.7 and a cost premium of about $100/ton over electric chillers and comparable maintenance and availability. In addition, an optional heat recovery package can also provide 1.7 MBTU/hr of hot water to meet thermal demands. Due to the adjustable speed of the gas engine, the chiller can achieve high efficiencies at partial load and improved load-following performance. The system design includes microprocessor controls to optimize efficiency by controlling engine speed and inlet guide vanes.

Tecochill field tested a 25-ton packaged rooftop air conditioning unit consisting of a Carrier Weathermaker II converted to a gas engine-driven system. The system has high efficiency controls that include variable engine speed, two stages of unloading on the reciprocating compressor, and a projected COP of 1.0.

Carrier Corp. / Tecochill Joint Marketing

Carrier Corp. is jointly marketing these systems with Tecochill. The Tecochill 150-ton gas engine-driven water chiller was commercialized in 1988 and well over 100 units have been sold (1992). Field tests are being conducted on two 500-ton and one 250-ton chillers. The Tecogen engine-driven chillers are expected to reduce customer's cost by at least 30 percent.

Thermo King Corp. Engine-Driven Rooftop and Split Systems

Thermo King Corp. has developed a 15-ton rooftop air conditioner for smaller commercial buildings driven by a Hercules natural gas-fueled engine. An optional 80 percent efficient furnace can also be added to the rooftop system to provide heating. The cooling capacity is 15 tons with a COP of 1.0 and the heating capacity is 216,000 Btu/hr. The 15-ton rooftop unit has been commercially available since 1990 and a 25-ton unit is expected to be available soon.

Thermo King has recently introduced a 15-ton split system in which the refrigeration system is located outdoors with an indoor blower and evaporator coil. This system was designed to accommodate a wider range of buildings with zoned heating and cooling systems. A number of manufacturers specialize in custom design and construction of engine-driven chillers. Custom systems can be tailored to meet specific space-cooling and process-cooling needs.

Fuel Cells

A fuel cell is an electrochemical device that converts fuel directly into electricity and heat. In a typical fuel cell, gaseous fuels are continually fed to the anode and an oxidant (usually air) is continually fed to the cathode. The electrochemical reaction takes place at the electrodes to produce electricity. Although a fuel cell is similar to a battery, the maximum energy available in a battery is determined by the finite amount of stored reactant. Because a fuel cell is fed a continuous supply of fuel and oxidant, it can theoretically produce energy as long as these inputs are available.

A typical fuel cell consists of an electrolyte sandwiched between two thin porous electrodes (Figure 20). Gaseous fuel and oxidant flow past the backside of the anode and cathode, respectively. The porous electrodes allow the fuel and oxidant to pass through and react on the surface of the electrodes. The ions migrate through the electrolyte and react at the surface of the other electrode to complete the electric circuit. Figure 21 shows a typical fuel cell module.

Major developments in fuel cell technology occurred with NASA's decision in the early 1960s that fuel cells were an appropriate power source for space use. NASA conducted an extensive research program to study the basic physics and reactions of fuel cells, develop methods to manufacture cell components, and construct workable cells. One of the first major successes of this research was in the Gemini series of earth-orbiting missions, which used alkaline fuel cells. In the late 1960s, electric and gas utilities began funding research to further develop fuel cells for stationary power production.

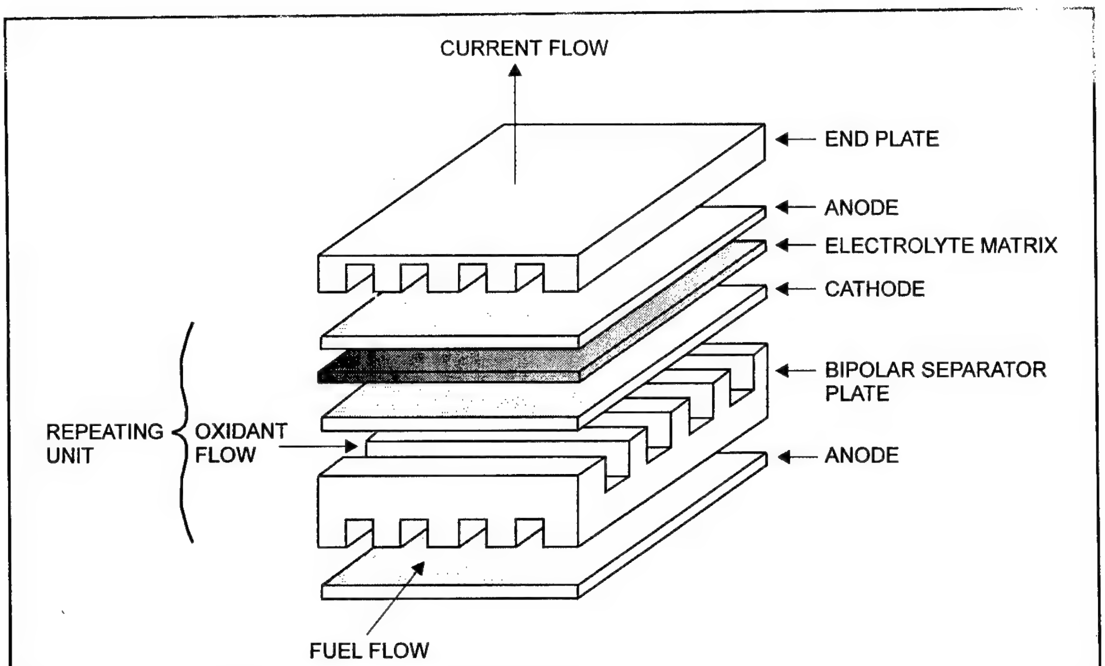


Figure 20. The repeating unit in a typical fuel cell stack.

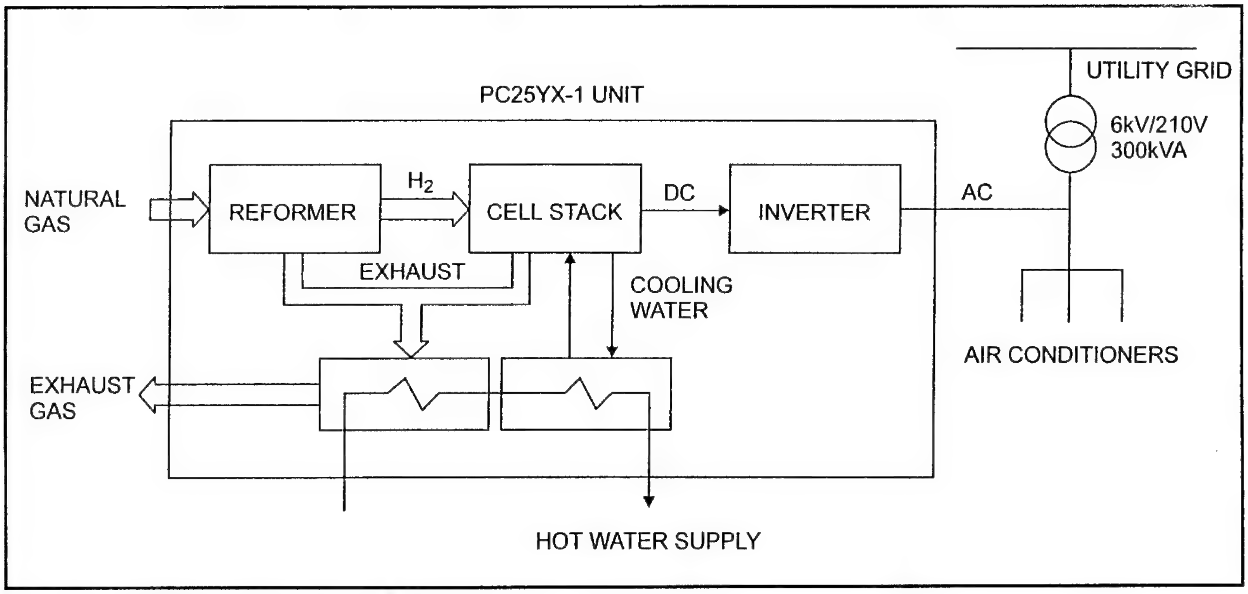


Figure 21. Fuel cell system for a PAFC stack.

Fuel cells have many advantages over other power producing technologies. One of the primary benefits is their high fuel-to-electricity conversion efficiency, which can approach 60 percent. Another benefit of fuel cells is their potential wide range of capacities, from 10s of kilowatts to 100s of megawatts. This allows greater flexibility in optimizing fuel cell system design. Finally, fuel cells perform very well under partial load conditions with very nearly constant heat rates from 25 percent of capacity to full load (Figure 22).

There are basically five types of fuel cells, generally classified by the type of electrolyte used:

1. Phosphoric Acid Fuel Cell (PAFC)
2. Molten Carbonate Fuel Cell (MCFC)
3. Solid Oxide Fuel Cell (SOFC)
4. Polymer Exchange Membrane Fuel Cell (PEMFC)
5. Alkaline Fuel Cell (AFC).

The PAFC and PEMFC are currently being developed for transportation applications. The AFC, which has long been used as a space power supply, continues to be developed and is finding new terrestrial applications. The PAFC, MCFC, and SOFC are the most suitable for larger power generation stations, while the PEMFC technology is making inroads into the smaller stationary power generation systems.

While PAFC and PEMFC are currently entering the commercialization stage, research and development of these and other fuel cells continues. Besides continuing basic fuel

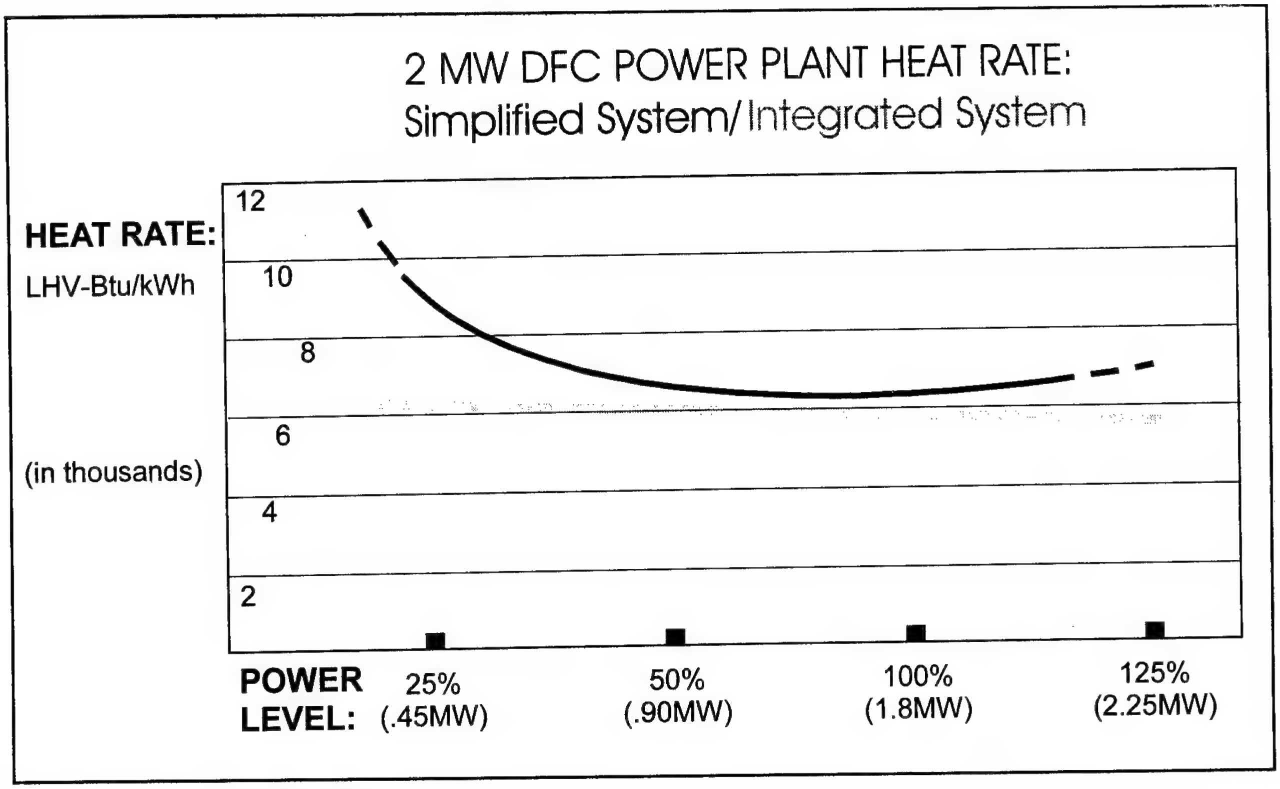


Figure 22. Typical fuel cell heat rate.

cell research, ongoing work is aimed at improving power density, manufacturability, stack life, and reducing system costs—currently at about $3,000/kW (January 1995) for the PAFC and somewhat less for the PEMFC. These costs are about twice the current cost of a gas engine or turbine cogeneration system. It is expected that, with future improvements in manufacturing techniques and increases in production, these costs will be reduced to about $1,000 to $1,500/kW when the market is fully developed.

4 Pertinent Issues Concerning Cogeneration

Ownership

Of several options for ownership that potentially apply to DOD cogeneration systems, the three most likely are:

1. DOD-owned and operated
2. Third-party owned, designed, and operated
3. DOD owned/third-party designed and operated.

For a DOD-owned and operated system, the DOD has responsibility for all costs associated with design, construction, maintenance, and operation of the cogeneration system. This method provides the greatest benefit to the DOD in that it minimizes all expenses (i.e., payment to third party owners, etc.) by the DOD.

With third party ownership, the cogeneration developer assumes all of the responsibility for the cogeneration project, including the design, construction, operation, and maintenance. The developer typically requires a contract before constructing the project to guarantee that the electrical and thermal energy produced will be purchased by the DOD. In return, the developer guarantees to provide the DOD energy at a cost below the current utility rates, typically about a 10 percent reduction. This method offers the DOD several advantages, including minimizing capital expenditures, and minimizing risk (potential maintenance problems, etc.), and is probably a better method for getting a large cogeneration system installed faster. However, this method reduces savings to the DOD since the developer retains the "profit" generated by the system in return for accepting the risk associated with the project. This is probably the most reliable method of maintaining a cogeneration system as the developer guarantees a savings to the DOD whether or not the system is operating. Therefore, it is in their best interest to properly maintain the system.

With a DOD-owned/third party-designed and operated arrangement, the cogeneration developer designs, constructs, and assists in the operation and maintenance of the system. This method offers the DOD greater benefits in reduced energy costs, but also requires a large capital expenditure to purchase equipment and increases the risk

associated with ownership should a problem occur. Third-party maintenance contracts can be both efficient and cost-effective.

Environmental Regulations

The Environmental Protection Agency (EPA) office for the area in which the cogeneration system is to be located should be contacted to determine the required pollution control equipment and regulatory steps for federal, state, and local environmental approval. Emissions from diesel or natural gas combustion are the primary source of air pollution. The primary air pollutants contributed by cogeneration systems are volatile organic carbons (VOCs) and nitrogen oxides (NO_x).

Federal water pollution standards apply to facilities that generate electricity for distribution and sale. Facilities with a capacity rated less than 25 MW are exempt from these standards unless they are part of an electric utility system with a total net capacity greater than 150 MW. The cogeneration system combustion process may also produce water pollution from cooling towers that are subject to National Pollutant Discharge Elimination System (NPDES) permitting.

In most cases, the amounts of water pollutants and solid waste generated from natural gas- or diesel-fired engines and turbines are small, provided that they burn a low-sulfur fuel. Cogeneration facilities can generally dispose of any water used for cooling into the municipal sewer. For these facilities, a municipal sewer permit may be required. However, some states require that noncontaminated cooling water be discharged into the storm sewer. The discharge of wastewater into a storm sewer also requires a NPDES permit.

Any facility that requires an oil storage tank capacity in excess of 1320 gal above ground or 40,000 gal below ground will require a Spill Prevention, Control, and Countermeasure (SPCC) Plan.

Regulatory Issues

The Federal Energy Regulatory Commission (FERC), in accordance with Section 201 of the Public Utility Regulatory Policies Act (PURPA) of 1978, requires an average, year-round efficiency of greater than 42.5 percent to be considered a qualifying facility. This efficiency is to be calculated according to the following relationship:

$$E = EE + (TE/2) \quad \text{[Eq 1]}$$

where:

E = FERC-defined cogeneration efficiency

EE = electrical output as a percentage of fuel energy input

TE = used heat output as a percentage of fuel energy input.

For example if an electrical generator has an efficiency of 30 percent (EE = 30), the minimum value of used thermal energy efficiency (TE) for a qualified cogenerator (E = 42.5 percent) can be calculated as:

$$42.5 = 30 + TE/2 \Rightarrow TE = 25$$

It will generally not be difficult to meet and/or exceed the FERC requirements for fuel efficiency for an economically feasible cogeneration system.

Utility Interconnection and Backup

While the signing of PURPA into law in 1978 required utilities to purchase excess electricity from small power producers, it did leave the utilities with a lot of flexibility as to how to calculate the value of the cogenerated electricity, utility interconnection requirements, and contracts for backup or standby power should the cogeneration system be down for maintenance or due to a component failure. These issues are typically negotiated with the specific utility serving the cogeneration host. Depending on the nature of the utility rate schedule, the generating capacity of the system, and the attitude of the utility toward cogeneration, it is possible that no backup power contract will be required.

The National Electric Code (NEC) prescribes proper techniques for cogeneration system/utility interconnection. Local utilities may require more stringent safety regulations than the NEC and must always be contacted before a cogeneration system is brought on line. The utility company will require that no electricity can be backfed into the utility grid when the power is out, such as after weather damage, to protect the linemen repairing the power lines. Discussions with the local utility should be one of the first steps taken after a preliminary analysis has determined that cogeneration is feasible.

5 Economic Benefits of Cogeneration to the DOD

Cogeneration analysis can be broken down into three categories depending on the available site information and the effort to be expended. A Level I analysis is a screening analysis and uses an annual thermal-to-electric ratio, considers a variety of power cycles (prime movers), and considers a very preliminary design and budget estimate. The accuracy of this analysis is approximately ± 30 percent and typically requires 5 to 10 hours to perform. The typical result of a Level I analysis is to rule out nonfeasible cogeneration projects.

A Level I analysis was performed to determine the cost effectiveness of cogeneration at 55 DOD facilities located in the region served by the Western Area Power Administration (WAPA) (King and Lorand 1991; King, Jennings, and Scholten 1991). The methodology and results of this study follow.

Data Collection and Reduction

The Defense Energy Information System (DEIS) database was used to obtain average and peak values for the electrical and steam requirements at each facility. An estimate of the cogeneration system electrical capacity was calculated by multiplying the peak electrical power demand by the ratio of the annual average monthly electrical consumption to the peak monthly electrical consumption. Estimating the cogeneration system electrical capacity in this manner does not allow the entire peak requirement of the facility to be met. Also, the system will at times have excess capacity. This method of determining system capacity was considered to be the approximate maximum level of cost effective cogeneration implementation for any facility. Table 10 shows the average and peak electrical energy and steam requirements, peak electrical demand, and estimated cogeneration system capacity for the facilities investigated.

Table 10. Cogeneration system design capacity.

		Average Month Loads (1)		Peak Month Loads (1)		Peak Annual Power	Cogeneration System Design Capacity (4)
	DOD Facility	Steam (MBtu)	Electric (MWh)	Steam (MBtu)	Electric (MWh)	Electric (MW)	Electric (MW)
	Colorado-Wyoming						
1	Pueblo Army Depot(2)	11,726	1,070	24,890	1,441	3.4	2.5
2	Fort Carson(2)	91,949	8,536	175,515	9,778	15	13.1
3	USAF Academy(2)	46,561	6,568	72,431	9,537	17	11.7
4	Peterson AFB(2)	11,038	4,159	21,183	6,763	7.5	4.6
5	Rocky Mountain Arsenal(3)	?	577	?	844	2	1.1
6	Fitzsimons AMC(3)	31,656	2,375	50,800	3,120	6	4.5
7	Buckley ANGB(n,2)	---	---	---	---	10	---
8	Lowry AFB(2)	38,974	5,651	75,024	6,801	16	13.3
9	Warren AFB(3)	23,267	4,846	44,588	5,577	11	9.2
10	Cheyenne Mtn-Spcom(2)	18,541	1,707	19,424	2,213	3	2.3
11	Falcon AFB(2)	2,787	3,656	4,796	3,960	6.4	5.9
	Totals	276,499	39,145	488,651	50,034		
	Western Texas-						
	New Mexico						
12	Fort Bliss(2)	75,796	12,687	181,218	15,292	29	24.1
13	White Sands Missile Range(2)	24,477	6,527	54,991	8,866	22	16.2
14	Holloman AFB(2)	14,377	4,087	40,715	5,821	15	10.5
15	Reese AFB(3)	8,096	2,255	17,176	2,780	5	4.3
16	Cannon AFB(3)	11,412	2,773	28,602	3,521	7	5.3
17	Kirtland AFB(2)	47,899	6,381	96,400	9,649	54	35.7
18	Fort Wingate Depot(c,3)	962	138	3,639	565	1	0.3
	Totals	183,019	34,848	422,741	46,494		

Notes:
(n) DEIS data not available.
(c) On base closure list.
(3) Peak Annual Power estimated by multiplying the Fort Bliss peak annual power by the ratio of Peak Month Load for a given facility to the Peak Month Load for Fort Bliss.
(4) Calculated by multiplying the peak annual power by the ratio of average month load to peak month load.

		Average Month Loads (1)		Peak Month Loads (1)		Peak Annual Power	Cogeneration System Design Capacity (4)
	DOD Facility	Steam (MBtu)	Electric (MWh)	Steam (MBtu)	Electric (MWh)	Electric (MW)	Electric (MW)
	Arizona						
19	Navajo Depot(c,n)	---	---	---	---	---	---
20	Naval Observ. Flagstaff(t?,n)	---	---	---	---	---	---
21	Luke AFB(2)	7,151	6,688	22,546	9,535	18.7	13.1
22	Davis-Monthan AFB(2)	10,949	4,861	23,855	6,052	16.4	13.2
23	Fort Huachuca(2)	34,567	7,792	85,190	9,491	18.5	15.2
24	Williams AFB(2)	6,091	3,790	13,887	5,559	13	8.9
25	Yuma Proving Ground(2)	1,076	2,756	3,393	3,648	8.6	6.5
26	MC Air Station Yuma(2)	5,411	3,965	10,286	5,653	11	7.7
	Totals	65,245	29,852	159,157	39,938		
	Southern/Central						
	California-						
	Southern Nevada						
27	El Centro NAS(3)	760	992	1,585	1,425	3	1.9
28	San Diego NAS(3)	4,025	3,766	13,996	4,392	8	7.1
29	San Diego Naval Station(3)	7,809	2,604	13,002	3,995	8	4.9
30	San Diego Naval Hospital(3)	3,992	2,992	6,048	3,621	7	5.7
31	Coronado Amphibious Base(3)	2,255	1,741	9,188	1,929	4	3.3
32	North Island NAS(3)	19,811	5,283	38,361	6,008	11	10.0
33	Camp Pendleton(3)	61,701	10,346	171,777	11,838	22	19.6
34	Port Hueneme Construct. Bat.(3)	13,600	1,945	58,847	2,364	4	3.7
35	Pacific MTC Port Mugu(3)	13,857	6,314	22,491	6,863	13	12.0
36	Norton AFB (c,3)	19,436	6,315	37,657	7,968	15	12.0
37	March AFB(3)	9,240	4,436	18,548	5,635	11	8.4

Notes:
(n) DEIS data not available.
(c) On base closure list.
(3) Peak Annual Power estimated by multiplying the Fort Bliss peak annual power by the ratio of Peak Month Load for a given facility to the Peak Month Load for Fort Bliss.
(4) Calculated by multiplying the peak annual power by the ratio of average month load to peak month load.

		Average Month Loads (1)		Peak Month Loads (1)		Peak Annual Power	Cogeneration System Design Capacity (4)
	DOD Facility	Steam (MBtu)	Electric (MWh)	Steam (MBtu)	Electric (MWh)	Electric (MW)	Electric (MW)
38	Naval Station-Long Beach(3)	7,415	1,640	15,047	1,839	3	3
39	Naval Hospital-Long Beach(3)	3,587	2,532	5,381	2,812	5	4.8
40	Naval Shipyard-Long Beach(3)	21,508	9,209	33,420	13,820	26	17.5
41	El Toro MAS(3)	8,423	3,690	19,617	5,368	10	7.0
42	Seal Beach Naval Weapon Stn(3)	3,063	1,189	5,942	1,386	3	2.3
43	Marines-29 Palms(2)	20,108	4,549	30,954	6,472	15	10.5
44	Edwards AFB(2)	31,251	11,488	70,691	14,877	48	37.1
45	MC Logistic Center-Barstow(2)	16,429	2,386	33,820	2,793	8.7	7.4
46	Navl Weapon Cntr China Lake(2)	45,570	8,590	91,955	10,830	19.2	15.2
47	Fort Irwin(2)	14,841	4,025	34,738	6,529	13	8.0
48	George AFB (c,2)	9,633	3,589	25,902	4,414	10.7	8.7
49	Nellis AFB(2)	14,762	7,853	38,632	10,343	26	19.7
50	Indian Springs Field(n)	---	---	---	---	---	---
	Totals	353,076	107,474	797,599	137,521		
	Utah						
51	Ogden Defense Depot(n)	---	---	---	---	---	---
52	Hill AFB(3)	95,681	17,321	224,102	22,317	42	32.8
53	Fort Douglas (c,n)	---	---	---	---	---	---
54	Tooele Army Depot(3)	28,526	3,288	61,087	3,776	7	6.2
55	Dugway Proving Ground(3)	13,870	2,035	29,953	2,384	5	3.9
	Totals	138,077	22,644	315,142	28,477		

Notes:
(n) DEIS data not available.
(c) On base closure list.
(3) Peak Annual Power estimated by multiplying the Fort Bliss peak annual power by the ratio of Peak Month Load for a given facility to the Peak Month Load for Fort Bliss.
(4) Calculated by multiplying the peak annual power by the ratio of average month load to peak month load.

Table 13. Levelized costs for cogeneration options.

	DOD Facility	Base Case Electricity Cost (1989$/kWh)	Cogeneration Electricity Cost (1)		Cogeneration Electricity Cost(1)		Lowest Cogeneration Cost < Base Case Electricity Price (%)
			Steam Topping Retrofit	Reciprocating Generator(2)	Gas Turbine(2)	Gas Combined Cycle(2)	
				(1989 $/kWh)	(1989$/kWh)		
	Colorado-Wyoming						
1	Pueblo Army Depot	0.017	0.045	0.061	0.072	0.064	Base Case Least Cost
2	Fort Carson	0.000	0.032	0.040	0.042	0.041	27
3	USAF Academy	0.041	0.027	0.036	0.037	0.035	33
4	Peterson AFB	0.034	0.049	0.050	0.067	0.056	Base Case Least Cost
5	Rocky Mountain Arsenal	0.048	0.045				6
6	Fitzsimons AMC	0.052	0.029	0.039	0.036	0.037	45
7	Buckley ANGB(n)	---	---	---	---	---	---
8	Lowry AFB	0.052	0.036	0.044	0.047	0.044	30
9	Warren AFB	0.044	0.031	0.040	0.046	0.041	30
10	Cheyenne Mtn-Spcom	0.051	0.035	0.043	0.036	0.042	30
11	Falcon AFB	0.030	0.070	0.066	0.088	0.075	Base Case Least Cost
	Western Texas-						
	New Mexico						
12	Fort Bliss	0.060	0.032	0.040	0.047	0.042	46
13	White Sands Missile Range	0.069	0.049	0.054	0.065	0.056	29
14	Holloman AFB	0.066	0.055	0.060	0.072	0.063	15
15	Reese AFB	0.052	0.043	0.047	0.057	0.050	17

Notes:
(n) DEIS data not available
(c) On base closure list
(t) Transferred out of DOD oversight
(1) Includes cogeneration capital and O&M costs assumed to be 1989 dollars
(2) Includes cost of steam service as credit.

	DOD Facility	Base Case Electricity Cost (1989$/kWh)	Cogeneration Electricity Cost (1) Steam Topping Retrofit	Cogeneration Electricity Cost (1) Reciprocating Generator(2) (1989 $/kWh)	Cogeneration Electricity Cost(1) Gas Turbine(2) (1989$/kWh)	Cogeneration Electricity Cost(1) Gas Combined Cycle(2)	Lowest Cogeneration Cost < Base Case Electricity Price (%)
16	Cannon AFB	0.045	0.046	0.050	0.060	0.053	Base Case Least Cost
17	Kirtland AFB	0.066	0.038	0.056	0.054	0.049	43
18	Fort Wingate Depot(c)	0.023	0.051	0.060	0.065	0.058	Base Case Least Cost
	Arizona						
19	Navajo Depot(c,n)	---	---	---	---	---	---
20	Naval Observ. Flagstaff(t?,n)	---	---	---	---	---	---
21	Luke AFB	0.059	0.072	0.070	0.093	0.079	Base Case Least Cost
22	Davis-Monthan AFB	0.057	0.066	0.064	0.083	0.070	Base Case Least Cost
23	Fort Huachuca	0.053	0.056	0.059	0.072	0.065	Base Case Least Cost
24	Williams AFB	0.053	0.066	0.066	0.087	0.073	Base Case Least Cost
25	Yuma Proving Ground	0.024	0.084	0.081	0.106	0.090	Base Case Least Cost
26	MC Air Station Yuma	0.057	0.067	0.065	0.087	0.073	Base Case Least Cost
	Southern/Central						
	California-						
	Southern Nevada						
27	El Centro NAS	0.065	0.096	0.089	0.121	0.102	Base Case Least Cost
28	San Diego NAS	0.052	0.116	0.107	0.148	0.125	Base Case Least Cost
29	San Diego Naval Station	0.063	0.079	0.082	0.113	0.094	Base Case Least Cost
30	San Diego Naval Hospital	0.067	0.058	0.057	0.075	0.063	16

Notes:
(n) DEIS data not available
(c) On base closure list
(t) Transferred out of DOD oversight
(1) Includes cogeneration capital and O&M costs assumed to be 1989 dollars
(2) Includes cost of steam service as credit.

	DOD Facility	Base Case Electricity Cost (1989$/kWh)	Cogeneration Electricity Cost (1) Steam Topping Retrofit	Reciprocating Generator(2) (1989 $/kWh)	Cogeneration Electricity Cost(1) Gas Turbine(2) (1989$/kWh)	Gas Combined Cycle(2)	Lowest Cogeneration Cost < Base Case Electricity Price (%)
31	Coronado Amphibious Base	0.074	0.061	0.061	0.080	0.068	18
32	North Island NAS	0.072	0.046	0.017	0.030	0.021	77
33	Camp Pendleton	0.067	0.038	0.042	0.051	0.045	44
34	Port Hueneme Construct. Bat.	0.092	0.037	0.043	0.050	0.044	60
35	Pacific MTC Port Mugu	0.088	0.058	0.055	0.076	0.063	38
36	Norton AFB (c)	0.092	0.051	0.053	0.069	0.058	44
37	March AFB	0.087	0.066	0.064	0.087	0.073	26
38	Naval Station-Long Beach	0.071	0.041	0.045	0.056	0.049	42
39	Naval Hospital-Long Beach	0.042	0.057	0.056	0.075	0.063	Base Case Least Cost
40	Naval Shipyard-Long Beach	0.068	0.048	0.048	0.066	0.055	30
41	El Toro MAS	0.081	0.076	0.073	0.100	0.083	10
42	Seal Beach Naval Weapon Stn	0.092	0.071	0.069	0.094	0.078	25
43	Marines-29 Palms	0.069	0.046	0.050	0.063	0.053	34
44	Edwards AFB	0.026	0.068	0.075	0.095	0.081	Base Case Least Cost
45	MC Logistic Center-Barstow	0.080	0.042	0.050	0.055	0.050	48
46	Navl Weapon Cntr China Lake	0.061	0.043	0.047	0.057	0.051	30
47	Fort Irwin	0.093	0.059	0.061	0.076	0.068	36
48	George AFB (c)	0.085	0.071	0.072	0.093	0.079	16
49	Nellis AFB	0.049	0.053	0.058	0.073	0.062	Base Case Least Cost

Notes:
(n) DEIS data not available
(c) On base closure list
(t) Transferred out of DOD oversight
(1) Includes cogeneration capital and O&M costs assumed to be 1989 dollars
(2) Includes cost of steam service as credit.

	DOD Facility	Base Case Electricity Cost (1989$/kWh)	Cogeneration Electricity Cost (1): Steam Topping Retrofit	Cogeneration Electricity Cost (1): Reciprocating Generator(2) (1989 $/kWh)	Cogeneration Electricity Cost(1): Gas Turbine(2) (1989$/kWh)	Cogeneration Electricity Cost(1): Gas Combined Cycle(2)	Lowest Cogeneration Cost < Base Case Electricity Price (%)
50	Indian Springs Field(n)	---	---	---	---	---	---
	UTAH						
51	Ogden Defense Depot(n)	---	---	---	---	---	---
52	Hill AFB	0.046	0.031	0.039	0.043	0.040	34
53	Fort Douglas (c,n)	---	---	---	---	---	---
54	Tooele Army Depot	0.060		0.047	0.060		22
55	Dugway Proving Ground	0.050	0.053	0.056	0.064	0.059	Base Case Least Cost

Notes:
(n) DEIS data not available
(c) On base closure list
(t) Transferred out of DOD oversight
(1) Includes cogeneration capital and O&M costs assumed to be 1989 dollars
(2) Includes cost of steam service as credit.

Table 14. Electricity cost savings: cogeneration option vs. purchased electricity.

	DOD Facility	Electricity Consumed (1) MWh	Base Case: Purchase Electricity		Least Cost Cogeneration		Savings	
			Levelized Unit Cost (1989 $/kWh)	Total Annual Cost (1989 K$/yr)	Levelized Unit Cost (1989 $/kWh)	Total Annual (2) Cost (1989 K$/yr)	(K$/yr)	(%)
	Colorado-Wyoming							
1	Pueblo Army Depot	12,845	0.017	215	0.017	215	Base Case	Least Cost
2	Fort Carson	102,436	0.044	4,470	0.032	3,290	1,180	26
3	USAF Academy	78,812	0.041	3,225	0.027	2,207	1,018	32
4	Peterson AFB	49,907	0.034	1,688	0.034	1,688	Base Case	Least Cost
5	Rocky Mountain Arsenal	6,925	0.048	331	0.045	314	17	5
6	Fitzsimons AMC	28,503	0.052	1,485	0.029	841	644	43
7	Buckley ANGB(n)	---	---	---	---	---	---	---
8	Lowry AFB	67,811	0.052	3,532	0.036	2,509	1,023	29
9	Warren AFB	58,149	0.044	2,580	0.031	1,833	747	29
10	Cheyenne Mtn-Spcom	20,489	0.051	1,035	0.035	747	288	28
11	Falcon AFB	43,866	0.030	1,314	0.030	1,314	Base Case	Least Cost
	Totals	469,743		19,875		14,957	4,918	25
	Western Texas-							
	New Mexico							
12	Fort Bliss	152,249	0.060	9,075	0.032	5,095	3,980	44
13	White Sands Missile Range	78,321	0.069	5,380	0.049	4,069	1,311	24
14	Holloman AFB	49,043	0.066	3,215	0.055	2,776	439	14

Notes:
(n) DEIS data not available.
(c) On base closure list.
(t) Transferred out of DOD oversight.
(1) Represents the annual electricity supply requirement .
(2) Where cogeneration is least cost: cogeneration system output * cost cogeneration levelized unit cost + (annual electricity supply requirement) * purchased electricity levelized unit cost.

	DOD Facility	Electricity Consumed (1) MWh	Base Case: Purchase Electricity Levelized Unit Cost (1989 $/kWh)	Base Case: Purchase Electricity Total Annual Cost (1989 K$/yr)	Least Cost Cogeneration Levelized Unit Cost (1989 $/kWh)	Least Cost Cogeneration Total Annual (2) Cost (1989 K$/yr)	Savings (K$/yr)	Savings (%)
15	Reese AFB	27,065	0.052	1,399	0.043	1,176	222	16
16	Cannon AFB	33,280	0.045	1,497	0.045	1,497	Base Case	Least Cost
17	Kirtland AFB	76,575	0.066	5,060	0.038	3,145	1,915	38
18	Fort Wingate Depot(c)	1,661	0.023	38	0.023	38	Base Case	Least Cost
	Totals	418,194		25,664		17,797	7,867	31
	Arizona							
19	Navajo Depot(c,n)	---	---	---	---	---	---	---
20	Naval Observ. Flagstaff(t?,n)	---	---	---	---	---	---	---
21	Luke AFB	80,253	0.059	4,767	0.059	4,767	Base Case	Least Cost
22	Davis-Monthan AFB	58,337	0.057	3,313	0.057	3,313	Base Case	Least Cost
23	Fort Huachuca	93,498	0.053	4,958	0.053	4,958	Base Case	Least Cost
24	Williams AFB	45,474	0.053	2,402	0.053	2,402	Base Case	Least Cost
25	Yuma Proving Ground	33,069	0.024	787	0.024	787	Base Case	Least Cost
26	MC Air Station Yuma	47,578	0.057	2,707	0.057	2,707	Base Case	Least Cost
	Totals	358,209		18,934		18,934	0	0

Notes:
(n) DEIS data not available.
(c) On base closure list.
(t) Transferred out of DOD oversight.
(1) Represents the annual electricity supply requirement .
(2) Where cogeneration is least cost: cogeneration system output * cost cogeneration levelized unit cost + (annual electricity supply requirement) * purchased electricity levelized unit cost.

	DOD Facility	Electricity Consumed (1) MWh	Base Case: Purchase Electricity		Least Cost Cogeneration		Savings	
			Levelized Unit Cost (1989 $/kWh)	Total Annual Cost (1989 K$/yr)	Levelized Unit Cost (1989 $/kWh)	Total Annual (2) Cost (1989 K$/yr)	(K$/yr)	(%)
	Southern/Central							
	California-							
	Southern Nevada							
27	El Centro NAS	11,899	0.065	773	0.065	773	Base Case	Least Cost
28	San Diego NAS	45,195	0.052	2,354	0.052	2,354	Base Case	Least Cost
29	San Diego Naval Station	31,244	0.063	1,957	0.063	1,957	Base Case	Least Cost
30	San Diego Naval Hospital	35,901	0.067	2,421	0.057	2,052	369	15
31	Coronado Amphibious Base	20,896	0.074	1,553	0.061	1,276	277	18
32	North Island NAS	63,396	0.072	4,533	0.017	1,196	3,337	74
33	Camp Pendleton	124,155	0.067	8,308	0.038	4,740	3,568	43
34	Port Hueneme Construct. Bat.	23,345	0.092	2,154	0.037	929	1,225	57
35	Pacific MTC Port Mugu	75,771	0.088	6,684	0.055	4,191	2,493	37
36	Norton AFB (c)	75,782	0.092	6,946	0.051	4,041	2,905	42
37	March AFB	53,236	0.087	4,607	0.064	3,468	1,139	25
38	Naval Station-Long Beach	19,684	0.071	1,393	0.041	836	558	40
39	Naval Hospital-Long Beach	30,386	0.042	1,291	0.042	1,291	Base Case	Least Cost
40	Naval Shipyard-Long Beach	110,509	0.068	7,510	0.048	5,445	2,065	27
41	El Toro MAS	44,276	0.081	3,591	0.073	3,278	313	9

Notes:

(n) DEIS data not available.
(c) On base closure list.
(t) Transferred out of DOD oversight.
(1) Represents the annual electricity supply requirement .
(2) Where cogeneration is least cost: cogeneration system output * cost cogeneration levelized unit cost + (annual electricity supply requirement) * purchased electricity levelized unit cost.

	DOD Facility	Electricity Consumed (1) MWh	Base Case: Purchase Electricity		Least Cost Cogeneration		Savings	
			Levelized Unit Cost (1989 $/kWh)	Total Annual Cost (1989 K$/yr)	Levelized Unit Cost (1989 $/kWh)	Total Annual (2) Cost (1989 K$/yr)	(K$/yr)	(%)
42	Seal Beach Naval Weapon Stn	14,268	0.092	1,309	0.069	989	321	24
43	Marines-29 Palms	54,590	0.069	3,772	0.046	2,626	1,146	30
44	Edwards AFB	137,860	0.026	3,583	0.026	3,583	Base Case	Least Cost
45	MC Logistic Center-Barstow	28,632	0.080	2,289	0.042	1,244	1,045	46
46	Navl Weapon Cntr China Lake	103,084	0.061	6,327	0.043	4,534	1,793	28
47	Fort Irwin	48,295	0.093	4,472	0.059	3,129	1,343	30
48	George AFB (c)	43,072	0.085	3,682	0.071	3,109	574	16
49	Nellis AFB	94,241	0.049	4,643	0.049	4,643	Base Case	Least Cost
50	Indian Springs Field(n)	---	---	---	---	---	---	---
	Totals	1,289,717		86,154		61,684	24,470	28
	Utah							
51	Ogden Defense Depot(n)	---	---	---	---	---	---	---
52	Hill AFB	207,848	0.046	9,633	0.031	6,514	3,119	32
53	Fort Douglas (c,n)	---	---	---	---	---	---	---
54	Tooele Army Depot	39,450	0.060	2,360	0.047	1,866	493	21
55	Dugway Proving Ground	24,424	0.050	1,226	0.050	1,226	Base Case	Least Cost
	Totals	271,722		13,220		9,607	3,612	27

Notes:

(n) DEIS data not available.
(c) On base closure list.
(t) Transferred out of DOD oversight.
(1) Represents the annual electricity supply requirement.
(2) Where cogeneration is least cost: cogeneration system output * cost cogeneration levelized unit cost + (annual electricity supply requirement) * purchased electricity levelized unit cost.

Table 14 also lists the costs of cogenerated electricity for comparison with utility purchased electricity. When the utility costs are less than the cogeneration costs, the base case is the least-cost option. When cogenerated electricity is the least-cost option, the potential dollar savings and percent reduction in cost are listed in the table. The dollar savings are estimated assuming that the cogeneration capacity installed is equal to that listed in Table 10. The percent possible reduction in operating costs ranges from zero (where utility purchased electricity is less expensive than cogeneration) to over 25 percent savings in one third of the facilities evaluated. All of these facilities with a demonstrated potential for operating cost reduction should carefully evaluate their future electrical and thermal energy requirements and consider the potential of cogeneration to help meet those needs.

Total estimated savings for all facilities is in excess of $40 million annually (Table 14). Figure 23 shows a breakdown of the potential savings (size of the pie slice) and percent cost reduction (percent CR) by region. The percent cost reduction is approximately the same for all regions (except Arizona), and the greatest potential for savings are in the California-Nevada region.

If the facilities with potential savings greater than 25 percent alone are considered as potential cogeneration applications (one-third of the facilities evaluated), the savings are still over $36 million annually.

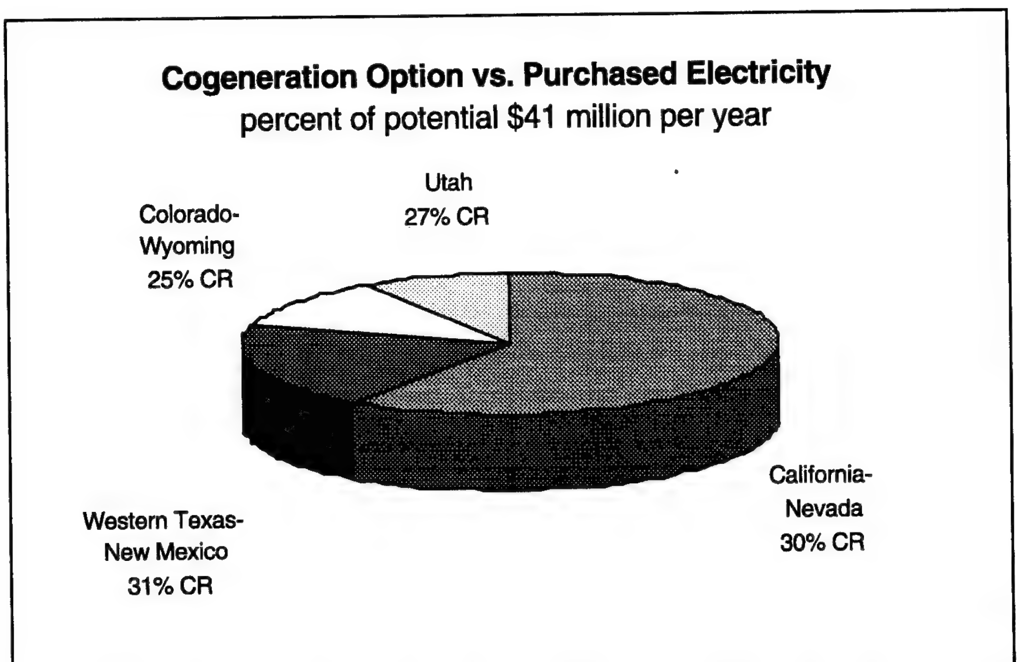


Figure 23. Potential electric cost savings.

As stated at the beginning of this chapter, the study discussed here considered the potential savings at 55 DOD facilities with electricity provided by WAPA. When all DOD facilities are considered, the potential savings would be significantly greater. A similar study evaluating all other DOD facilities is recommended.

6 Conclusions and Recommendations

This report has summarized the benefits of cogeneration, outlined typical applications, and described relevant analysis tools that can help installation planners determine whether cogeneration is an economically feasible energy generation alternative at a given site. This report also summarized the current state of the art in cogeneration technologies available currently or in the near future. Each of the four main subsystems (prime mover, generator, heat recovery, and control) were discussed and the economic benefits of cogeneration were presented.

This study concludes that, in general, cogeneration systems can be a very cost effective method of providing the military with its energy needs. The Western Area Power Authority, which encompasses 55 DOD installations in eight states in the southwestern United States, was selected as a typical region for preliminary analysis. An analysis using DEIS data for these installations showed that, even if the pool of possible cogeneration sites were limited to installations with potential savings greater than 25 percent (slightly more than one-third of the installations evaluated), the potential annual savings would exceed \$36 million. If all DOD installations were considered, the potential saving would be significantly greater.

It is recommended that a similar study evaluating all other DOD installations be conducted to identify the potentially economically attractive sites. It is also recommended that all installations that show economic benefits from cogeneration consider it a viable alternative to increasing power purchases from the utility. This is particularly true at installations that are capacity constrained due to undersized electrical substations and/or transmission lines.

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Appendix A: Available Computer Software for Cogeneration Analysis

Program Name: ACE (Associated Cogeneration Evaluation)

Intended Purpose of Program

ACE is designed to evaluate the technical and economic performance of cogeneration systems. Some features of the program include:

- Treats multiple (up to three) thermal energy streams, including a chilled water stream
- Considers multiple (up to three) cogeneration units in the overall system
- Handles time-varying electrical and thermal loads
- Simulates shutdown of cogeneration units for maintenance or at predetermined (or calculated) times of low-load
- Evaluates several different system types, including reciprocating engine, gas turbine, and steam turbine; with and without an absorption chiller and thermal storage in the system
- Accurately simulates the effects of part-load operation of various units
- Evaluates economic impacts of forced outages
- Considers both variable and fixed O&M cost components
- Considers non-uniform inflation and escalation rates
- Considers tax implications and various ownership options
- Calculates net present value and internal rate of return
- Can consider specific electric utility rate structures, to accurately capture demand charge, "ratchet," and declining block effects
- Can be used to find the optimum type, size, and number of units in the cogeneration installation. (The cost impacts of different combinations of parameter values are quickly investigated during one set of computer runs. There is no limit to the number of runs in a given set or "study.")

System(s) the Program Runs On

The software was designed for IBM-PC, PCAT, PCXT, DEC Rainbow 100+, or other similar computers with a minimum of 256K memory.

Estimated Complexity and Ease of Operation

- Very "User-Friendly" (data input via previously entered file, or interactively via a terminal)
- Checks key input parameters for "reasonableness" at time of entry; error messages are displayed when necessary to guide inputting of valid data

Availability of Program and Cost

The price of ACE is $900 and includes three utility rates. Additional tariffs may be added at $100 each. Contact the following for additional purchasing details:

TechPlan Associates, Inc.
15 Cynwyd Road
Bala Cynwyd, PA 19004
215/667-8366

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

Developed by Mr. William Steigelmann

Program Name: CELCAP (Civil Engineering Laboratory Cogeneration Analysis Program)

Intended Purpose of Program

CELCAP can analyze cogeneration systems comprised of gas turbines, diesel engines, extraction steam turbines, and back pressure steam turbines. In the program, a waste heat boiler model is included in the gas turbine and diesel engine models. CELCAP can analyze a system consisting of any combination of these four types up to a maximum of five engines. The input to the program consists of the design point and part load performance of the engines, utility rate structure, fuel costs and escalation rates, operation and maintenance costs, and escalation rates for the engines. The electric and steam loads are input as two 24-hour profiles (working day and nonworking day) for each month of the year.

System(s) the Program Runs On

CELCAP runs on IBM PC/XT/AT computers or compatibles with a hard disk, a minimum of 400K RAM, an 8087 math co-processor, and MS DOS 3.1 with RESTORE.COM.

Estimated Complexity and Ease of Operation

The input processor provides a user-friendly data interface with the CELCAP program. However, the rate schedule of the main program must be modified to properly calculate the cost of power purchased from the utility and the revenue for power sold to the utility. This is a proven procedure and has been performed by the Naval Civil Engineering Laboratory several times during cogeneration studies of six Navy bases.

Availability of Program and Cost

The program is in the public domain and is available for a nominal charge by contacting:

Dr. Richard Lee
Naval Civil Engineering Laboratory
Port Hueneme, CA 93043
805/982-1670

Availability of Documentation

Users documentation is available with the software.

Person(s) Responsible for Program

To obtain copies of the program or technical information contact:

Dr. Richard Lee
Naval Civil Engineering Laboratory
Port Hueneme, CA 93043
805/982-1670

Program Name: CEPP (Cogeneration and Energy Planning Program)

Intended Purpose of Program

Encotech's Cogeneration and Energy Planning Program (CEPP) was designed primarily to perform the following two tasks:

- Accurately predict the annual operating costs of meeting a plant's electrical, thermal, and mechanical needs by means of a designated mix of energy conversion equipment either with or without the involvement of the local electric utility.
- Perform economic evaluations of alternatives by identifying the incremental return on investment of an alternative as compared to a base case or another alternative.

System(s) the Program Runs On

IBM-PC compatibles with a minimum of 512K RAM.

Estimated Complexity and Ease of Operation

Features of the program that improve user interfacing are as follows:

- Interactive, user-friendly format
- Self guiding documentation
- 16 worksheets to organize data collection and entry.

Availability of Program and Cost

The CEPP program can be purchased for $2,495. This includes a generic machine data bank and load profiles as well as a complete users manual. Contact the following for purchase information:

Encotech, Inc.
207 State Street
PO Box 714
Schenectady, NY 12301-0714
518/374-0924

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

John M. Daniels, the Marketing Director for Encotech, can be contacted for additional details regarding the software purchase and use.

Program Name: CFAM (Cogeneration Feasibility Analysis Model)

Intended Purpose of Program

CFAM was developed for analyzing cogeneration systems for commercial and institutional applications. The program also has the ability to perform a building energy analysis.

The CFAM program models building electrical, heating, and cooling loads using ASHRAE procedures and weather data. The user can select the weather locations from a list of 60 possible locations. A typical weekday and weekend load profile for each month is used in the analysis. CFAM performs an analysis for the following four system configurations:

- Total electric (no utility interconnection)
- Total thermal
- Base electric
- Peak shaving.

The cogeneration equipment consists of gas turbines or gas engines with heat recovery equipment and an absorption chiller if desired. The number of units and size of the equipment may be either specified by the user or designed by CFAM. The program outputs include a monthly energy use summary, a cash flow analysis, and estimates for the net present worth and internal rate of return for the four operational configurations.

System(s) the Program Runs On

CFAM system requirements are an IBM or compatible PC with 256K of RAM, MS-DOS 2.10 operating system, and two disk drives.

Estimated Complexity and Ease of Operation

The program is menu-driven and user-friendly. Data collection forms are included in the users manual to facilitate the data collection and entry procedure.

Availability of Program and Cost

The program is available at a purchase price of $1,700 from:

Reynolds, Smith and Hills
Architects-Engineers-Planners, Inc.
PO Box 4850
Jacksonville, FL 32201
904/739-2000

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

Contact Mr. Paul Hutchins at the following address for additional details:

Reynolds, Smith and Hills
Architects-Engineers-Planners, Inc.
PO Box 4850
Jacksonville, FL 32201
904/739-2000

Program Name: COAL DIESEL (Diesel Engine Performance Study)

Intended Purpose of Program

COAL DIESEL calculates the performance of a diesel engine using coal/water slurry as fuel and diesel oil as pilot fuel. The diesel cycle is divided into nine regimes, and macroscopic equilibrium is assumed at regime interfaces. The regimes considered are: turbo-compression, intercooling, diesel compression, constant volume expansion, exhaust and scavenging, and turbo-expansion.

System(s) the Program Runs On

XEROX Sigma 9, with CPV operating System

Availability of Program and Cost

The source code (Program A 388 lines, Program B 427 lines) is available on magnetic tape for approximately $1200 plus a $100 special-handling fee from:

National Energy Software Center
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Availability of Documentation

N/A

Person(s) Responsible for Program

J.P. Davis and C.C. Wang
Energy Systems Division
Thermo Electron Corporation

Program Name: COGEN

Intended Purpose of Program

COGEN performs a complete thermodynamic and financial analysis to evaluate the economic benefits of installing a back pressure steam turbine/generator unit for in-plant cogeneration of electricity and process steam. The program assists in determining the optimum size turbine/generator for the energy demand characteristics of the plant.

System(s) the Program Runs On

COGEN runs under MS-DOS (or PC-DOS), versions 1.1 or later, and MBASIC on the IBM PC, PC-Jr., other PC compatibles, and the Texas Instruments Professional Computer. A minimum of 128K of RAM and one double-density disk drive are required. A printer is recommended but not required.

Estimated Complexity and Ease of Operation

All inputs are requested in standard engineering terminology and instructions for data entry are automatically presented on screen.

Availability of Software and Cost

The one-time license fee of $145 for COGEN includes the program, User's Manual, and a 1 year free update service warranty. The program can be purchased from the following:

Software Systems
PO Box 26065
Austin, TX 78755
512/451-8634

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

Additional information concerning the software may be obtained by contacting Donna Schmidt, the Manager of Sales and Distribution at the following address:

Software Systems
PO Box 26065
Austin, TX 78755
512/451-8634

Program Name: COGEN3

Intended Purpose of Program

COGEN3 Version 1.4 combines the capabilities of conceptual engineering design, costing, economic optimization, and financial evaluation of cogeneration projects. Users enter prices for fuel and electricity and data on the thermal and electric loads to be supplied by the cogeneration system. From this data, COGEN3 determines the equipment selection and operation, fuel selection, and electricity sales or arrangement with the electric utility that supplies the thermal and electric loads at the lowest total cost. COGEN3 then performs a financial analysis of the optimal design. The analysis incorporates the provisions of the new tax law as they relate to cogeneration.

System(s) the Program Runs On

IBM mainframe systems.

Estimated Complexity and Ease of Operation

COGEN3 requires no special computer skills. Easy English-like, self-documenting data entry procedures and commands are used.

Availability of Software and Cost

COGEN3 is available in one of three ways. Mathtech can prepare your cogeneration analyses using the COGEN3 system for you. If you have access to a terminal, COGEN3 is available on a national time-sharing network. If your organization has an IBM or compatible mainframe and you want to maintain a high level of confidentiality, a ten year license or annual rental plans are available. Mathtech offers a full range of support services for COGEN3 including maintenance, training, telephone support and consulting.

For more information contact:

Mathtech, Inc.
Suite 200
210 Carnegie Center
Princeton, NJ 08540

Availability of Documentation

The following EPRI reports are available from the EPRI Research Reports Center (415) 965-4081:

COGEN3: A Computer Model for Design, Costing and Economic Optimization of Cogeneration Projects, Final Report EPRI EA-3955 (August 1984).

Cogeneration Case Studies Using the COGEN2 Model, EPRI EA-2114 (June 1982).

Forecasting In-Plant Electricity Generation in the Industrial Sector, 1980-2000, EPRI EA-2163, Chapter 4 (December 1981).

Person(s) Responsible for Program

Mathtech Inc., under EPRI contract RP1538-02 is responsible for the COGEN3 program. Contact the following individuals for additional information:

Marcus Duff	609/520-3893
Ernest H. Manuel	609/520-3870

Mathtech, Inc.
Suite 200
210 Carnegie Center
Princeton, NJ 08540

Program Name: COGENMASTER

Intended Purpose of Program

COGENMASTER evaluates cogeneration options by comparing them with a base case scenario in which a facility purchases electricity from a utility and produces thermal energy on-site. The model allows the user to examine the technical and economic feasibility of cogeneration options and to prepare detailed cash flow statements. The code can screen a variety of ownership arrangements, technologies and operating strategies. The reports output can be as brief as a one page summary or as detailed as a seven page monthly break down of energy and demand costs.

System(s) the Program Runs On

The program will run on any IBM-compatible personal computer using DOS version 2.11 or higher, a base memory of 512k, a 360k or 720k floppy drive and a hard drive. Optional equipment requirements include a graphics card to view and print load shape plots and a printer to print reports and graphs.

Estimated Complexity and Ease of Operation

COGENMASTER is menu-driven and user-friendly. It incorporates explanatory help screens to guide the user through the data input process. Default values are provided for all data requests.

Availability of Program

For further information, contact the Electric Power Software Center at 214-655-8883.

Availability of Documentation

The following EPRI reports are available from the EPRI Research Reports Center, 415-965-4081.

Cogeneration and Utilities: Status and Prospects, EPRI EM-6096 (November 1988).

COGENMASTER: A Model for Evaluating Cogeneration Options, EPRI EM-6102, vol 1 and 2 (December 1988).

Small Cogeneration System Costs and Performance, EPRI EM-5954 (August 1988).

Person(s) Responsible for Program

Technical information regarding the program can be obtained from Hans Gransell and Bill LeBlanc, Project Managers at 415/855-2887 or by writing:

Electric Power Research Institute
3412 Hillview Ave.
PO Box 10412
Palo Alto, CA 94303

Program Name: COGENT

Intended Purpose of Program

COGENT is a diagnostic tool for the performance evaluation of gas turbine co-generation systems. It enables the operator to predict the expected performance of cogeneration systems in a variety of steam generating configurations.

COGENT analyzes the following as turbine power systems: (1) simple cycle where the exhaust gas is rejected to the atmosphere; (2) combined cycle where the turbine exhaust is used to generate steam to drive a steam turbine; (3) water or steam injected cycle; and (4) a cogeneration cycle where the exhaust gas heat is used to generate wet, saturated or superheated steam.

COGENT incorporates advanced technology developed by the Electric Power Research Institute (EPRI) and the Gas Research Institute (GRI). A variety of gas turbine cycles may be analyzed including those with a heat recovery boiler and an optional steam turbine power cycle.

System(s) the Program Runs On

COGENT runs entirely on the IBM PC and incorporates full color graphics for display and plotting of results. COGENT requires 512K RAM, a 10-meg hard disk, DOS 3.0 or higher operating system and a fully-configured IBM PC or compatible, with either monocolor, CGA, or EGA compatible color graphics.

Estimated Complexity and Ease of Operation

COGENT provides an integrated set of structured menus, and a detailed User's Manual to guide the user in modeling the cogeneration system.

Availability of Program and Cost

The program is available from:

Fern Engineering, Inc.
55 Portside Drive
PO Box 3380
Pocasset, MA 02559
508/563-7181

Availability of Documentation

N/A

Person(s) Responsible for Program

Additional information concerning the program can be obtained from:

Fern Engineering, Inc.
55 Portside Drive
PO Box 3380
Pocasset, MA 02559
508/563-7181

Program Name: DHSM (District Heating/Cooling Strategy Model)

Intended Purpose of Program

DHSM determines the feasibility of hypothetical hot water district heating and cooling systems using thermal energy primarily from retrofit of existing central station electric generating facilities for cogeneration capability. It was not developed to make preliminary or final design analyses nor as a linear programming optimization model.

System(s) the Program Runs On

The program runs on an IBM 3033 with VM/CMS operating system.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

Source code is available on magnetic tape from:

National Energy Software Center
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Availability of Documentation

The following references are available:

Brubaker, Kenneth L., Polly Brown, and Richard R. Cirillo, *Addendum to User's Guide for Climatological Dispersion Model*, EPA-450/3-77-015 (May 1977).

Busse, A.D., and J.R. Zimmerman, *User's Guide for the Climatological Dispersion Model*, EPA-R4-73-024 (PB-227346) (December 1973).

Energy Systems Research Group, Inc., *District Heating Strategy Model User's Guide*, Draft User Guide (3 February 1981).

Hrabak, R.A., N.F. Kron, Jr., and W.P. Pferdehirt, *District Heating Strategy Model: Community Manual*, ANL/CNSV-TM-94 (October 1981).

Kuzanek, J.F., *District Heating Strategy Model: Computer Programmer's Manual*, ANL/CNSV-TM-115 (May 1982).

Person(s) Responsible for Program

J.F. Kuzanek
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Program Name: MICRO-DOE2

Intended Purpose of Program

MICRO-DOE2 performs energy use analyses for residential and commercial buildings. It is used for: the design of new, energy-efficient buildings; the analysis of existing buildings for energy-conserving modifications; and the calculation of design budgets. It is intended for use by architects and engineers with a basic knowledge of the thermal performance of buildings.

The output data are arranged in lists or tables according to the format of a standard output report. If a user wishes to examine a particular variable that is not available in a standard output report, he may select the variable and print its hourly values through the REPORT program.

System(s) the Program Runs On

- Microcomputer - IBM PC, XT, AT, COMPAQ DESKPRO 386, or true compatible Disk Operating System PC DOS or MS DOS 2.10 or later
- Random Access Memory - 640K
- Math Co-processor - INTEL 8087 or 80287
- Hard Disk Drive - 20meg
- Floppy Disk Drive - 360K or 1.2meg (for installation only)
- Monitor
- Printer

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

The DOE-2 computer program is available from:

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
703/487-4650

Availability of Documentation

N/A

Person(s) Responsible for Program

N/A

Program Name: GATE/CYCLE (Gas Turbine Evaluation)

Intended Purpose of Program

GATE/CYCLE is a powerful set of analytical tools for predicting the design and off-design performance of gas-turbine-based power plant systems. The GATE (Gas Turbine Evaluation) code performs detailed steady-state analyses of gas turbine engines. CYCLE is a modular heat-balance steam cycle analysis program that can analyze essentially any steam bottoming cycle for gas turbine power plants. These two programs work together or separately to analyze all or selected portions of power plant systems.

The GATE/CYCLE code computes and outputs the key performance characteristics of gas-turbine/steam-cycle systems. These results include plant heat rate, system temperatures, pressures and flow rates, and performance characteristics (such as efficiency) of all major components in the gas turbine and associated steam cycle. The GATE/CYCLE code can display these results on plots, data forms, and text report files.

System(s) the Program Runs On

The GATE/CYCLE software runs on IBM-PC compatible computers with a hard disk and a graphics card. A numeric co-processor is recommended, and a mouse is optional.

Estimated Complexity and Ease of Operation

These programs use an integrated set of structured menus, tailored forms, and full-color graphical flowsheet diagrams to guide users in setting up power system simulation problems.

Availability of Program and Cost

For a single-user license, GATE/CYCLE and an EASE+ runtime module may be purchased for $10,000 for the first year, and $2,000 for each additional year.

Additional copies are available for use within licensing organization at 50 percent of the single user price for the first copy, and 25 percent for each additional copy, plus the cost-of EASE+ runtime modules. Site licenses are also available at additional discounts. EASE+ runtime modules are available for $600 when licensed with GATE/CYCLE.

Availability of Documentation

N/A

Person(s) Responsible for Program

For additional technical information contact:

M.R. Erbes
R.R. Gay
Enter Software, Inc.
805 Evergreen St.
Menlo Park, CA 94025
415/322-6610

Program Name: GTPRO/GTMASTER

Intended Purpose of Program

GTPRO is a preliminary tool for feasibility studies on gas turbine cogeneration and combined cycle plants. The program yields detailed tabulations of the gas turbine and steam plant cycles and their subcomponents. Heat balance tables provide an audit of energy flow. Graphic outputs show the cycle flow diagram, heat recovery temperature profile, h-s and T-s diagrams. Output can be switched between metric and imperial units.

GTMASTER uses the hardware description generated by GTPRO and allows the user to modify it as needed to perform off-design analysis of selected plants by varying environmental and operating parameters.

System(s) the Program Runs On

IBM personal computer compatibles operating on DOS version 3.0 or later with 640k RAM. The plotter for graphic results must be fully HP-compatible.

Estimated Complexity and Ease of Operation

Approximately 120 inputs describe a combined cycle. Proficient use of the program predicted within a few days.

Availability of Program and Cost

The GTPRO software can be obtained for $3,500 per year on a simple lease. Both programs are available for $6,000 per year. This price includes maintenance and selected upgrades during that period.

A perpetual lease for the GTPRO software can be obtained for $10,000 and $20,000 for both. This price includes 1 year of maintenance and upgrades. Optional maintenance and upgrades after the first year are $750 per year.

Availability of Documentation

N/A

Person(s) Responsible for Program

For technical information regarding the software contact Dr. Maher Elmasri, president of Thermoflow Inc. at the following address:

Thermoflow Inc.
9 Clubhouse Ln.
Wayland, MA 01778
508/655-8576

Program Name: ICOP (Financial Model Industrial Cogeneration)

Intended Purpose of Program

The ICOP program performs financial analysis computations in a generic fashion, with special emphasis on the analysis of industrial cogeneration applications. Both discounted and undiscounted cash flows are generated. Measures of financial feasibility include energy savings, internal rate of return, and net present value.

The cash flow is computed based on construction and capital costs, interest, operations and maintenance, insurance, replacement, fuel and electricity costs, depreciation, tax on capital, and delta income tax. Annual cost components are computed from an initial base and an annual factor.

System(s) the Program Runs On

The ICOP program is designed for use on the CDC CYBER 170 and 175. The operating system is MACE, the TRW-modified KRONOS Operating System (CDC CYBER 170), NOS 1.4 (CDC CYBER175). ICOP is adaptable to other computer systems with minor modifications.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

The source code program is available (on cards) for approximately $1200 plus a $100 special-handling fee from:

National Energy Software Center
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Availability of Documentation

Related references are as follows:

Handbook of Industrial Cogeneration, DOE/TIC-11605 (October 1981).

TRW Energy Engineering Division Memorandum, Subject: "ICOP Program" (December 1981).

Person(s) Responsible for Program

Technical information can be obtained from:

L.M. Green and H.F. Burnworth, Jr.
Energy Engineering Division TRW
8301 Greensboro Drive
McLean, VA 22102

Program Name: LOADSHAPER

Intended Purpose of Program

The Cogen Module is available as an integral part of the LOADSHAPER system and allows the user to evaluate the economic benefits and costs of a proposed cogeneration system in a new or existing facility side-by-side with other alternatives, such as conventional fuel and electricity supply, efficient heating, cooling or process equipment, thermal energy storage, etc.

The Cogen Module allows a user to size a proposed cogen system to meet the facility's electric and thermal loads. It recognizes the different operating and performance characteristics of various prime movers such as reciprocating engines, gas turbines, steam turbines, and fuel cells and guides the user through the sizing steps in a simplified manner. The consequences of the type, size, and electric and thermal performance of a prime mover chosen can be seen in monthly and hourly outputs. Other reports and graphs targeted at decision makers can be used to show actual system performance in terms of monthly expenditures, present value cash flow analysis, and before and after comparisons. Also obtainable are percentages of loads met, supplemental requirements, cost of outages, and requirements for backup equipment.

As with other LOADSHAPER modules, the Cogen module provides default sizing and equipment characteristics. For example, the user can simply enter the operating strategy, the type of prime mover, and the thermal (or electric) end uses to be met by the cogen system. LOADSHAPER will size the equipment to meet the thermal loads, calculate the default electrical capacity, and provide default maintenance costs.

System(s) the Program Runs On

The program is designed for use on IBM PC, PC/XT, PC/AT, or compatibles with PC-DOS 2.0 or greater, a minimum 256K RA, two DSDD disk drives or hard disk, and an optional Intel 8087 or 80287 math co-processor available.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

LOADSHAPER pricing is based on program needs. Because the system is installed on individual computers, there are no timesharing or usage fees. The LOADSHAPER system can be configured to match the requirements of large energy utilities as well as those of small municipals or cooperatives. A one-time fee covers all software licenses, manuals, training, customization, and installation. It also includes support and maintenance for the first year (renewable annually).

For additional purchasing information contact:

MorganSystems Corporation
2560 Ninth Street, Suite 211
Berkeley, CA 94710
415/548-9616

Availability of Documentation

N/A

Person(s) Responsible for Program

MorganSystems Corporation
2560 Ninth Street, Suite 211
Berkeley, CA 94710
415/548-9616

Program Name: MESA (Modular Energy System Analyzer)

Intended Purpose of Program

MESA is an extensively used computer program that facilitates rapid modeling of all industrial energy systems. Features of the program are as follows:

- Performs a complete mass and energy balance while conforming to the First and Second Laws of Thermodynamics
- Analyzes cogeneration potential
- Analyzes proposed operational and design changes
- Optimizes operations for lowest cost
- Provides complete graphics output.

System(s) the Program Runs On

MESA runs on PC-compatibles with MS-DOS, 400K RAM, and a math co-processor. The program requires two double density drives or a hard disk. A graphics printer or plotter and mouse are recommended.

The program is also fully supported on DEC VAX machines as well as other mini- and mainframe computers.

Estimated Complexity and Ease of Operation

The program data inputs are interactive. The software contains extensive diagnostics.

Availability of Software and Cost

The program is available through:

The MESA Company
22 Golden Shadow Circle
The Woodlands, TX 77381
713/363-9337

Availability of Documentation

The following reference material is available:

Delk, S.R., *Applications for Computers in Industrial Powerhouse*, 79-IPC-Pwr-6, (ASME, New York, 18 July 1979).

Delk, Stephen R., and William Gary Jones, "Interactive Off-line Computer Modeling for Powerhouse Operations," *Proceedings of the Fourth Annual Industrial Energy Conservation Technology Conference & Exhibition* (Houston, Texas, 4-7 April 1982), pp 416-420.

Rhinehart, R. Russell, and Beasley, "Dynamic Programming for Chemical Engineering Applications," *Chemical Engineering* (7 December 1987), pp 113-119.

Person(s) Responsible for Program

Contact Stephen R. Delk for additional technical details:

The MESA Company
22 Golden Shadow Circle
The Woodlands, TX 77381
713/363-9337

Program Name: PC-BEACON

Intended Purpose of Program

PC-BEACON is a multizone building energy program that computes heating and cooling energy requirements for each hour of the year. Direct, indirect, insulated, and hybrid passive solar building can be simulated as well as conventional structures.

The program was originally designed to provide quick energy analysis of building envelope options, to aid in selection of the most cost effective configuration. However, PC-BEACON can be used for many purposes including equipment selection and energy conservation studies for existing buildings.

PC-BEACON uses transfer functions as defined in the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) 1977 and 1985 Handbook of Fundamentals to compute heat loss or gain through walls and roofs.

The program output can be used as an optional input for the Energy Requirements part of the PC-CUBE program (see section for PC-CUBE).

System(s) the Program Runs On

IBM Personal Computer or compatible operating on PC-DOS or MS-DOS 2.0 or higher. The computer must be equipped with at least 256K of memory and two floppy disk drives. A printer is desirable but not necessary.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

The price of PC-BEACON including documentation is $495. Purchase of PC-BEACON can be arranged through:

Energy Systems Engineers, Inc.
2530 S. Parker Rd., Suite 300
Aurora, CO 80014
303/696-6241

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

For additional information contact the following:

Donald C. Pedreyra,
Energy Systems Engineers, Inc.
2530 S. Parker Rd., Suite 300
Aurora, CO 80014
303/696-6241

Program Name: PC-CUBE

Intended Purpose of Program

PC-CUBE is used to estimate the hour-by-hour energy requirements of a commercial building or industrial central plant operation. It simulates the resulting energy that would be consumed by each piece of equipment, and even determines the various utility costs of each of the systems being compared.

System(s) the Program Runs On

IBM PC, XT, AT and compatible personal computers with 256K memory, an 8087/80287 math coprocessor and one 360K disk drive.

Estimated Complexity and Ease of Operation

PC-CUBE has a standalone program called CUBEIN that interacts with the user and prepares an input file acceptable to the program. The user merely positions the screen cursor on the data field to be changed or input and types in the desired value. In some cases the program checks the data to determine if the value is appropriate or within range. The user can move from one screen to another with no more than four key strokes.

Availability of Software and Cost

The price of PC-CUBE including documentation is $495. Purchase of PC-CUBE can be arranged through:

Energy Systems Engineer's, Inc.
2530 S. Parker Rd., Suite 300
Aurora, CO 80014
303/696-6241

Availability of Documentation

Available with purchase of software.

Person(s) Responsible for Program

Don Pedreyra was instrumental in the development of the software and is the President of Energy Systems Engineers, Inc. Mr. Pedreyra can be contacted at the following address for additional details concerning the program:

Energy Systems Engineers, Inc.
2530 S. Parker Rd., Suite 300
Aurora, CO 80014
303/696-6241

Program Name: PEGASYS (Performance Evaluation for GAS SYStems)

Intended Purpose of Program

The complete PEGASYS package can help the gas compressor station to become more energy efficient and can prolong the life of the gas turbine and regenerator by constantly tracking and trending the turbine performance data. The information provided by the diagnostic system signals operators when efficiency is down and cleaning or upgrading of components is needed to prevent unnecessary maintenance downtime.

System(s) the Program Runs On

PEGASYS runs on PC-compatibles with DOS 3.0 and higher, 640K RAM, a CGA or EGA monitor, and a math coprocessor.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

The program is available through:

Fern Engineering, Inc.
55 Portside Dr.
PO Box 3380
Pocasset, MA 02559
508/563-7181

Availability of Documentation

N/A

Person(s) Responsible for Program

Fern Engineering, Inc.
55 Portside Dr.
PO Box 3380
Pocasset, MA 02559
508/563-7181

Program Name: PEPSE (Performance Evaluation of Power Systems Efficiencies)

Intended Purpose of Program

PEPSE was developed for analyzing the steady-state performance characteristics of thermodynamic systems (power plants, boilers, etc.). It is used to analyze the performance of process steam generation, waste heat recovery and commercial steam electric generation cycles.

System(s) the Program Runs On

PEPSE Mainframe: IBM mainframe code versions (i.e., for mainframes equipped with a VS compiler and running under either the OS-VS or VM/CMS operating system).

PEPSE/PC: IBM PS2 Model 70, IBM PC XT/AT, 386 versions

Minimum hardware requirements for PEPSE/PC include:

- 2 meg of extended RAM
- Math Coprocessor
- 10-meg Hard Disk
- DOS 3.0
- Floppy Disk Drive.

Estimated Complexity and Ease of Operation

EIKON/PEPSE is a user-friendly personal-computer based input assistance and output presentation tool.

Availability of Program and Cost

Purchase of a PEPSE/PC license for a single PC costs $10,000. This includes the executable code and one set of supporting documentation. Additional single copies are available for $6,500 apiece. A system-wide license, permitting its use on multiple PCs and networks, is available for $25,000.

The mainframe and VAX versions of the PEPSE code are also available for $25,000 (without source).

The PEPSE Subscription Service is available to all PEPSE code licensees. The service fee is $6,500/licensee/year.

Licenses may be purchased from the following:

EI International, Inc.
PO Box 50736
545 Shoup Avenue
Shoup & B Plaza
Idaho Falls, ID 83402
208/529-1000

Availability of Documentation

Complete users documentation is available with the software.

Person(s) Responsible for Program

EI International, Inc.
PO Box 50736
545 Shoup Avenue
Shoup & B Plaza
Idaho Falls, ID 83402
208/529-1000

Program Name: SCAP (Small Cogeneration Analysis Program)

Intended Purpose of Program

SCAP is used to assess the economic potential of small packaged cogeneration systems (under 500 kW). The system will determine the useful thermal and electrical output and determine the total annual savings, simple payback period, and savings to investment ratio for a facility cogeneration installation. The system has built-in default thermal loads for a variety of building types or users may specify load profile. Similarly, defaults for equipment and maintenance costs are also provided.

System(s) the Program Runs On

IBM personal computers and compatibles.

Estimated Complexity and Ease of Operation

SCAP is menu driven and user friendly. The program is easy to run and can be used by a novice computer user. No programming knowledge is required. Thermal load data may be stored for future runs or default values may be used. The program computes the economic parameters for one system per run. One disadvantage of the program is that the input data must be re-entered each time the program is run. Data input forms accompany the program and can be used to organize the data required by the program.

Availability of Program and Cost

The (public domain) program is available for a nominal charge by contacting the following:

Dr. Richard Lee
Naval Civil Engineering Laboratory
Port Hueneme, CA 93043
805/982-1670

Availability of Documentation

Users documentation is available with the software.

Person(s) Responsible for Program

To obtain copies of the program or technical information contact the following:

Dr. Richard Lee
Naval Civil Engineering Laboratory
Port Hueneme, CA 93043
805/982-1670

Program Name: SERICPAC (Electric Utility Avoided Cost Rates)

Intended Purpose of Program

SERICPAC is a set of programs that calculates electric utility avoided cost rates when time-of-production metering is not feasible. It contains models that simulate the performance of wind turbines, low-head hydro facilities, and several biomass systems; accumulate production estimates by utility time period; and take the output from the companion SERICOST program which calculates an electric utility's avoided cost, and combine it with the time-correlated production estimates to calculate weighted average annual rates. The avoided cost is determined based on marginal costs. Each technology is modeled separately with wind power modeled on a component basis and other technologies modeled as simple hourly energy flows. Cogeneration production and marginal costs are used on a life cycle basis to calculate avoided cost to the utility. Only one cogeneration technology can be modeled in any given run.

System(s) the Program Runs On

The program is designed to run on a Vector Graphics VIP with a CP/M operating system. The software requires 56K memory and 400K disk storage.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

Source code on magnetic tape is available for approximately $700 plus a $100 special-handling fee from:

National Energy Software Center
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Availability of Documentation

The following related references are available:

Feldman, Stephen L., and Robert M. Wirtshafter, *On the Economics of Solar Energy* (Lexington Books, Lexington, MA, 1977).

Wirtshafter, Robert, Michael Abrash, Michael Koved, and Stephen Feldman, *A User's Guide to SERICPAC: A Computer Program for Calculating Electric Utility Avoided Costs Rates*, SERI/TR-09275-1 (May 1982).

Person(s) Responsible for Program

T. Flaim
Solar Energy Research Institute

Program Name: SERICOST (Avoided Cost of Electric Utilities)

Intended Purpose of Program

SERICOST is an interactive program used to calculate and perform sensitivity analyses on avoided costs of electric utilities connected with cogeneration and small power production facilities by time period, independent of the type of technology used by the qualifying facility. If the qualifying facility is large enough to justify time-of-production metering, then SERICOST alone can calculate appropriate rates. Otherwise SERICOST can provide input to a companion program, SERICPAC, which calculates weighted average annual rates. Used in combination, the two models calculate average annual avoided cost rates for wind turbines, low-head hydro facilities, and some biomass systems. The primary advantage of SERICOST and SERICPAC over other available models is that they can be used to estimate technology-specific avoided cost rates without having to rerun more complex utility planning models for every qualifying facility or technology type.

System(s) the Program Runs On

The program is designed for use on a UNIVAC1100 with EXEC8 operating system. The program requires 64K words to run.

Estimated Complexity and Ease of Operation

N/A

Availability of Program and Cost

Source code on magnetic tape at a cost of $1400 plus a $100 special handling fee is available from:

National Energy Software Center
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439
312/972-7250

Availability of Documentation

The following documentation is available:

Cicchetti, Charles, William Gillen, and Paul Smolensky, *The Marginal Costs and Pricing of Electricity: An Applied Approach* (Ballinger Publishing Company, Cambridge, MA, 1977).

Madison Consulting Group, *A User's Guide to SERICOST: A Computer Program for Estimating Electric Utility Avoided Cost*, SERI/TR-09275-2 (May 1982).

Person(s) Responsible for Program

T. Flaim
Solar Energy Research Institute

Program Name: STEAMBAL

Intended Purpose of Program

STEAMBAL is a program used to analyze industrial steam power cycles. The program performs a complete mass and energy balance of the plant to find the heat required and the power produced. The software can be used to evaluate new plants, test old plants, and evaluate alternative plant configurations.

System(s) the Program Runs On

IBM PC and compatibles.

Estimated Complexity and Ease of Operation

The user must write custom commands to model and analyze complex plants.

Availability of Program and Cost

Steambal is available on 5-1/4 inch floppy diskettes for $379. Annual updates are available for $39. The software can be purchased from the following:

Thermal Analysis Systems Company
725 Parkview Circle
Elk Grove Village, IL 60007
708/439-5429

Availability of Documentation

Users documentation is provided with the purchase of the software.

Person(s) Responsible for Program

Contact the following for additional technical information:

Thermal Analysis Systems Company
725 Parkview Circle
Elk Grove Village, IL 60007
708/439-5429

Program Name: Syntha II

Intended Purpose of Program

Design features of Syntha II are as follows:

- Predicts full-load and part-load performance of coal gasification, complete steam or air-cooled PFBC combined cycle power plants with selected load following controls.
- Predicts full-load and part-load performance of any nuclear, fossil, combined-cycle or STIG power plant for evaluating alternate designs.
- Optimizes feed water heat transfer surface areas to achieve minimum overall power plant cost including fuel and capital costs.

Surveillance features include:

- Establishes the flow, efficiency, and performance of each turbine section, heat exchanger, pump, etc. in the power plant.
- Tracks the performance over time of turbines, heat exchangers, pumps, etc. for use in power plant maintenance scheduling, and to avoid unscheduled outages.
- Evaluates the effect on heat rate and generation of equipment performance degradations to permit the maintenance cost/benefit analyses.
- Provides immediate answers to "what-if" questions relating to power plant heat rate and generation, with heater outages, plugged tubes, fouling, equipment out of service, etc.
- Updates the unit incremental heat rate curves for energy dispatch purposes.
- Evaluates the effect of various operating procedures (reducing boiler pressure vs. closing turbine control valves, etc.) on power plant part-load heat rate.

Optional features of the program are:

Automatic Graphical Output (AGO): At the request of the engineer, AGO will automatically prepare a schematic diagram of the power plant with the weight flow, pressure, temperature, and enthalpy printed at every flow stream location.

System(s) the Program Runs On

Syntha II is available for installation on CDC, IBM, or AMDAHL mainframes, Prime or VAX minis, or 386 personal computers.

Syntha II has passed all Quality Assurance tests on the Compaq 386 with only 2meg of RAM. The 20 MHz 80386 CPU chip and 20 MHz 80387 math coprocessor chip were selected. The operating system required is MS/PC DOS 2.0 or later.

Estimated Complexity and Ease of Operation

Power plant computer models can be easily created from vendor thermal packages, component or power plant test data, engineering equipment performance estimates, established computer performance prediction procedures, or any combination of the same.

Syntha provides unmatched technical capabilities in an easily used, engineering-oriented format that requires no computer experience. A brief training course (3 to 5 days) will enable an engineer to create a Syntha model of any power plant.

EASE+ will be available to enhance the ease-of-use of Syntha II and reduce its training requirements.

Availability of Program and Cost

The Syntha code for a 386 PC costs $15,000 with an additional $3,000 per year for program updates and user support.

EASE+ modules are available for an estimated $5,000 to $9,000.

The software can be purchased from the following:

Syntha Corporation
41 West Putnam Avenue
Greenwich, CT 06830
203/869-2703

Availability of Documentation

The following are publications describing the component performance prediction procedures utilized by Syntha II:

Bailey, F.G., J.A. Booth, K.C. Cotton, and E.H. Miller, *Predicting the Performance of 1800 RPM Large Steam Turbine-Generators Operating with Light Water-Cooled Reactors*, GET-6020 (General Electric Company).

Bailey, F.G., K.C. Cotton, and R.C. Spencer, *Predicting the Performance of Large Steam Turbine Generators Operating with Saturated and Low Superheat Steam Conditions*, GER-2454A (General Electric Company.

Keenan, Joseph H., and Joseph Kaye, *Gas Tables—Thermodynamic Properties of Air Products of Combustion and Component Gases* (John Wiley & Sons, Inc.).

McClintock, R.B. (General Electric Co.), and G.J. Silvestri (Westinghouse Electric Corp.), *Formulations and Iterative Procedures for the Calculation of Properties of Steam* (ASME 1968).

Salisbury, J.K.,*Optimization of Heater Design Conditions in Power Plant Cycles*, Publication 68-WA-12 (American Society of Military Engineers [ASME]).

Spencer, R.C., K.C. Cotton, and C.N. Cannon, *A Method of Predicting the Performance of Steam Turbine Generators, 16,500 kW and Larger*, GER-2007C (General Electric Company).

Standards for Closed Feedwater Heaters, 2d ed. (Heat Exchanger Institute, 1974).

Standards for Steam Surface Condensers, 7th ed. (Heat Exchanger Institute, 1978).

Standards of Tubular Exchanger Manufactures Association, 6th ed. (Tubular Exchanger Manufactures Association, Inc., 1978).

Person(s) Responsible for Program

Additional technical information can be obtained from:

Syntha Corporation
41 West Putnam Avenue
Greenwich, CT 06830
203/869-2703

Program Name: THE ENERGY ANALYST

Intended Purpose of Program

The Energy Analyst is a set of power plant design programs. The software will perform an economic analysis for cogeneration projects to determine the cost effectiveness of onsite power generation. The program will also calculate performance and economic parameters associated with the following:

- Insulation Economics
- Shell and Tube Exchanger
- Combustion Analysis
- Piping Pressure Drop
- Steam Surface Condenser
- Pipe Network
- Cooling Tower
- Steam Heater
- Steam Turbine
- Gravity Drains
- Heat Recovery Boiler
- Tower/Condenser
- Gas Compressor
- Gas Turbine
- Boiler Chimney
- Pump Calculations
- Nozzle Flow
- Flash Tank.

System(s) the Program Runs On

IBM PC and compatibles.

Estimated Complexity and Ease of Operation

The software is menu driven and user friendly.

Availability of Program and Cost

The Energy Analyst - Series 19 is available on 5-1/4 inch floppy diskettes for $299. Individual programs can be purchased for $99 each. Annual updates are available for $39. The software can be purchased from the following:

Thermal Analysis Systems Company
725 Parkview Circle
Elk Grove Village, IL 60007
708/439-5429

Availability of Documentation

Users documentation is provided with the purchase of the software.

Person(s) Responsible for Program

Contact the following for additional technical information:

Thermal Analysis Systems Company
725 Parkview Circle
Elk Grove Village, IL 60007
708/439-5429

Appendix B: List of Cited Manufacturers

Manufacturer	Location	Phone
Allison	PO Box 420 Indianapolis, IN 46206	317/242-3983
Alturdyne Energy System	8050-T Armour San Diego, CA 92111	619/565-2131
ASEA Brown Boveri	1460 Livingston Ave North Brunswick, NJ 08902	908/932-6000
Atlas Energy Systems, Inc.	16872-T Milliken Ave Irvine, CA 92713	714/863-0900
Baltimore Gas and Electric	7225 Windsor Blvd Baltimore, MD 21244	410/265-4650
Carrier Corp.	PO Box 4808 Syracuse, NY 13221	315/432-6000
Caterpiller, Inc.	100 N.E. Adams Peoria, IL 61629	309/675-1000
Cooper-Bessemer	150 Lincoln Ave Grove City, PA 16127	412/458-8000
Dresser Industries–Waukesha Engine	1600-T Pacific Building Dallas, TX 75201	214/740-6000
Dresser-Rand Co.	150-T Allen Road Liberty Corner, NJ 07938	908/647-6800
European Gas Turbines, Inc.	15950-T Park Row Houston, TX 77084	713/492-0222
General Electric Company	3135 Easton Turnpike Fairfield, CT 06431	800/626-2004
Institute of Gas Technology	1700 Mount Prospect Road Des Plaines, IL 60018	312/890-6466
Kawasaki Heavy Industries	3-1-1 Higashi Kawaski-Cho Chuo-Ku, Kobe-Shi Hyogo, 650-91 JAPAN	078/682-5133
Pacific Gas and Electric	3400 Crow Canyon Road San Ramon, CA 94583	510/866-5745

Manufacturer	Location	Phone
Pratt & Whitney	400 Main Street East Hartford, CT 06108	203/565-4321
Rolls Royce	PO Box 31 Derby, DE 24 8BJ UNITED KINGDOM	44-332-246703
Ruston Gas Turbines, Inc.	15950-T Park Row Houston, TX 77084	713/492-0222
Solar Turbines, Inc.	PO Box 85376 San Diego, CA 92186	619/544-5000
Stirling Power Systems Corp.	275-T Metly Drive Ann Arbor, MI 48103	313/665-6767
Tecogen, Inc.	PO Box 9046 Waltham, MA 02254	617/622-1400
Thermo King Corp	314 W. 90th Street Minneapolis, MN 55420	612/887-2200
Trane Co.	3600-T Pammel Creek Road La Crosse, WI 54601	608/787-2000
Westinghouse Electric Corp.	11 Stanwix Street Pittsburgh, PA 15222	407/281-2000
York International, Inc.	631-T Richland Ave. York, PA 17405	717/771-7890

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US Army Engr Division
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USA TACOM 48397-5000
ATTN: AMSTA-XE

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ATTN: ASCW-WG 95296-0100

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ATTN: AFZA-DPW-EE

4th Infantry Div (MECH) 80913-5000
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US Army Materiel Command (AMC)
Alexandria, VA 22333-0001
ATTN: AMCEN-F
Installations: (20)

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Forts Gillem & McPherson 30330
ATTN: FCEN
Installations: (21)

6th Infantry Division (Light)
ATTN: APVR-DE 99505
ATTN: APVR-WF-DE 99703

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Fort Monroe 23651
ATTN: ATBO-G
Installations: (20)

Fort Belvoir 22060
ATTN: CETEC-IM-T
ATTN: CETEC-ES 22315-3803
ATTN: Water Resources Support Ctr

USA Natick RD&E Center 01760
ATTN: STRNC-DT
ATTN: DRDNA-F

US Army Materials Tech Lab
ATTN: SLCMT-DPW 02172

USARPAC 96858
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SHAPE 09705
ATTN: Infrastructure Branch LANDA

Area Engineer, AEDC-Area Office
Arnold Air Force Station, TN 37389

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Walter Reed Army Medical Ctr 20307

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US Army CHPPM
ATTN: MCHB-DE 21010

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Nat'l Institute of Standards & Tech
ATTN: Library 20899

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Defense Construction Supply Center
ATTN: DCSC-WI 43216-5000

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Defense Tech Info Center 22060-6218
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